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Optimal tariff mix analyses using least squares state estimation and linear programming techniques /

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OPTIMAL TARIFF MIX ANALYSES USING LEAST SQUARES STATE ESTIMATION AND LINEAR PROGRAMMING TECHNIQUES

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Abstract

Utility tariff structures are often complex and difficult to understand. Many utilities are presently embarking on new Marketing and Economic Development programs with emphasis on creating new jobs by expanding existing industries and bringing new industries into the service territory. Some of the impacts of this endeavor are an overall increase in total load for the utility, variations in the peak load, and a change to the utilities' revenues. These factors are of great interest to both the utility and the customer. This paper examines the sensitivity of various loads (residential, industrial, commercial, other) and the impact on total load. Additionally, various tariffs are analyzed for the optimal mix in a marketing strategy. Recommendations are presented to optimize the mix of utility load groups.

Chapter I

Introduction

During the last decade both utilities and customers have experienced increasing costs for electric power. This is due to many variables including escalating costs for fuels that are used to generate electricity as well as the large capital costs for building new generation units or upgrading them to maximize reliability and availability. With the present regulatory climate there is also an ongoing effort to continuously strive to reduce overall costs. In other words, the utilities are continually working to minimize revenue requirements.

There are many ways to approach this difficult problem. Some of the options include:

* development of new and inexpensive generation facilities
* changing load patterns so that generation expansion is avoided or deferred
* minimizing revenue requirements
* load management applications
* revising utility tariffs

The costs for electricity vary considerably over the day, the week and the seasons of the year depending on the size of the total load and the marginal costs of the units that supply this demand.

The demand is also changing continuously due to :

* customers' habits

* weather conditions

* industrial activities

The customers' habits are sometimes easy to predict such as commercial and industrial business hours and street lighting hours while other loads such as heating and air conditioning are more unpredictable.

The major objective for the electric utility is to supply the customer with the quantity of electricity that is needed at every moment while also controlling peak demand, reliability and cost to the customer.

As the demand varies the utility must run production units that are sufficiently rated to meet the demand and that have the lowest marginal costs. The short run marginal costs are different for the various types of units depending on the differences in running costs (fuel types and running times). Overall, there is a desire to levelize the demand fluctuations in order to increase the running times for units with low marginal costs and to decrease the utilization of peaking units that inherently have high marginal costs, all with the objective to obtain lower overall electric energy costs.

Much work has been done under the label of "Load Management" in an effort to achieve lower overall electric energy costs. Load management analysis is generically the study of load and customer impacts resulting from the operation of load management programs. The results from such an analysis are generally used to determine the cost effectiveness of these programs and to report load savings obtained from past program activities.

Some of the approaches that have been used in load modeling were based on an analysis of previous system load data with a prediction of overall change based on periodicity and weather effects.[16,21] In general, no specific relationship between physical equipment and load was made for demand models although equipment characterization is utilized in response models.

Woodward,[31] proposed a model based in part on physical elements (for example, domestic water heaters) and in part on functional elements (for example, lighting load as determined by wattage per square foot and the area involved).

His switching functions are based on element response to a combination of environmental functions and life style functions, which are different for each category. He combines all of the elements of one type as one potential load. This is fractionally switched, partially by a life style function which used a multiple harmonic expansion to describe the function. The initial parameters needed for the function would be obtained from a year's worth of empirical data.

The development of other physically based models was reported. [8, 14, 19, 23, 26] These include various forms of aggregate component models with a usage function for each. The usage function includes or implies customer input, assumed to be specified elsewhere or obtained from empirical data or generated by various probability functions. Boeing Computer Services indicates they consider summing individual component models to obtain a residence load and summing residence loads to obtain a feeder load to be too complex to process.

They propose a customer level model based on cyclic and environmental time functions from which component level information could be extracted. A circuit based model, in which the coefficients of the describing differential equations are parameters represented by stochastic processes, has also been proposed.[14]

References 4 and 15 describe end use models in which the basic load curves for residential appliances are developed by analysis of recordings of actual use of the appliances.

Since the goal of incorporating load management into daily operations appears illusive and the process remains poorly defined, load management analysis such as load impact or load sensitivity studies can be undertaken that are consistent with utility program design and marketing strategies. This should assist utilities to better evaluate where load management efforts should be concentrated (residential, commercial, industrial groups, etc.) and to develop long term strategies that will minimize revenue requirements and maximize revenue generated.

This will be demonstrated in the following chapters by:

1. Comparing customer load groups to the total load with actual utility data and verify a good match for the overall model.
2. Examining the effects or sensitivity of load group characteristics by varying the sensitivity factor Alpha ( ) and illustrating the impact on the total load and the potential for benefit of shifting a given load group.
3. Optimizing the tariffs of an actual utility to analyze what the best load group mix should be based on these existing tariffs.

4. Providing conclusions and recommendations for a marketing strategy.

Chapter II

A Review of Mathematical Optimization Techniques

The aim of this chapter is to review the basic mathematical techniques used to:

1. Compare customer load groups to the total load and verify a good match for the overall model.
2. Examine the effects or sensitivity of load group characteristics by varying the sensitivity factor alpha (α) and illustrating the impact on the total load and the potential for benefit of shifting a given load group.
3. Optimize the tariffs of an actual utility to analyze what the best load group mix should be based on these existing tariffs.

This will be accomplished by a specific review of:

* vectors
* vector addition
* scalar multiplication
* euclidean inner product
* matrices
* matrix addition
* scalar and matrix multiplication
* partitioned matrices
* multiplication of partitioned matrices
* partitioned matrix inversion

* least squares estimation

* weighted least squares estimation

* linear programming

Vectors

Let P_1, P_2,....P_n be real (or complex) numbers and let P be an ordered set of these numbers written in the form

$$P = \begin{bmatrix} P_1 \\ P_2 \\ P_n \end{bmatrix} \quad \text{or } P = \text{col}[P_1, P_2,\ldots.P_n]$$

P is then called an n-column vector or simply, a column vector. The i th component or element of P is given by Pi. The concept of vector functions is an extension that assumes that the elements are functions of one or more variables (e.g. time). Here with $P_1(t)$, $P_2(t)$,...$P_n(t)$ being functions of time in an appropriately chosen space, one has the n th dimension vector[28]

$$P(t) = \text{col}[P_1(t), P_2(t),\ldots.P_n(t)]$$

Vector Addition

Let two vectors P and Q be given as:

$$P = \text{col}[P_1, P_2,\ldots.P_n]$$

$$Q = \text{col}[Q_1, Q_2,\ldots.Q_n]$$

The vectors are equal if their components are equal,

$$Pi = Qi \quad \text{for} \quad i = 1, 2,\ldots.n$$

The sum of the two vectors is written P+Q and defined to be the vector:

$$P + Q = col[P_1 + Q_1, P_2 + Q_2, \ldots. P_n + Q_n]$$

In general, the following laws apply:

$$P + Q = Q + P \quad \text{(commutative)}$$

$$(P + Q) + S = P + (Q + S) \quad \text{(associative)}$$

Multiplication of a vector P by a scalar alpha (α) is defined by means of the relation:

$$P = P\alpha = col[\alpha P_1, \alpha P_2, \ldots. \alpha P_n]$$

The euclidean inner product is a scalar function of two vectors P and Q and is written:[28]

$\langle P, Q \rangle$ and defined by the relationship

$$\langle P, Q \rangle = \sum_{i=1}^{n} PiQi$$

<u>Matrices</u>

An m x n matrice A is defined as a rectangular array of mn numbers

$$A = \begin{bmatrix} A_{11} & A_{12} \ldots. A_{1n} \\ A_{21} & A_{22} \ldots. A_{2n} \\ \ldots\ldots & \ldots\ldots\ldots \\ A_{m1} & A_{m2} \ldots. A_{mn} \end{bmatrix} = [aij]$$

The mn numbers aij are referred to as the matrix elements. The integers m and n associated with an m x n matrix refer to the numbers of rows and columns respectively. An n x n matrix is called a square matrix of order n. An m x 1 matrix is a column vector obeying all the rules of the preceding section on vectors. A 1 x n matrix is a row vector.

Elementary Matrix Operations

Two matrices A and B are said to equal if and only if:

$a_{ij} = b_{ij}$ for $i=1, 2,\ldots.m$, and

$j = 1, 2,\ldots,n$

In such a case one writes:

$$A=B$$

A matrix is multiplied by a scalar lamda (λ) if all mn elements are multiplied by lamda (λ), that is ,

$$\lambda A = A\lambda = \begin{bmatrix} \lambda a_{11} \cdots \lambda a_{1n} \\ \cdots\cdots\cdots\cdots\cdots\cdots \\ \lambda a_{m1} \cdots \lambda a_{mn} \end{bmatrix}$$

Addition and subtraction of two matrices result in new matrices in accordance with:

$$A \pm B = \begin{bmatrix} a_{11} \pm b_{11} \cdots a_{1n} \pm b_{1n} \\ \cdots\cdots\cdots\cdots\cdots\cdots \\ a_{m1} \pm b_{m1} \cdots a_{mn} \pm b_{mn} \end{bmatrix}$$

These operations apply only to matrices with the same numbers of rows and columns.

Matrix multiplication is defined to facilitate the operations necessary in connection with linear transformations. The linear transformation:[11]

$$y1 = a_{11}x_1 + a_{12}x_2 + \ldots + a_{1n}x_n$$

$$y2 = a_{21}x_1 + a_{22}x_2 + \ldots + a_{2n}x_n$$

$$\cdots\cdots\cdots\cdots\cdots\cdots\cdots\cdots\cdots\cdots$$

$$ym = a_{m1}x_1 + a_{m2}x_2 + \dots + a_{mn}x_n$$

or

$$yi = \sum_{j=1}^{n} a_{ij}x_j \quad \text{for } i = 1,2,\dots\dots,m$$

We now can consider formally the aij's as elements in an m x n matrix A and write the above equations in the form:

$$y = Ax$$

This symbolism will have no meaning, until we prescribe that the product Ax will mean an m vector whose i th component will be defined by

$$yi = \sum_{j=1}^{n} a_{ij}x_j \quad \text{for } i = 1,2,\dots\dots,m$$

This fully defines the matrix-vector product. The full power of the concept of matrix multiplication will be evident only upon definition of a matrix-matrix product. For that purpose a new linear transformation[11]

$$x1 = b_{11}z_1 + b_{12}z_2 + \dots + b_{1p}z_p$$

$$x2 = b_{21}z_1 + b_{22}z_2 + \dots + b_{2p}z_p$$

$$\dots\dots\dots\dots\dots\dots\dots\dots\dots\dots$$

$$xn = b_{n1}z_1 + b_{n2}z_2 + \dots\ b_{np}z_p$$

or

$$xk = \sum_{r=1}^{p} b_{kr}z_r \quad \text{for } k = 1,2,\dots\dots,n$$

Using the accepted shorthand notation, one can also write the last equations:

$$x = Bz$$

where B is an n x p matrix, and z is a p vector.

By substituting, one can eliminate the x components, and end up with the following m relations between y and z:

$$yi = \sum_{j=1}^{n} a_{ij} \sum_{r=1}^{p} b_{jr} z_r \quad \text{for} \quad i = 1,2,\ldots,m$$

One can rearrange the summation signs in this last expression

$$Yi = \sum_{r=1}^{p} \left(\sum_{j=1}^{n} a_{ij} b_{jr} \right) Z_r \quad \text{for} \quad i = 1,2,\ldots,n$$

and by introduction of the mp new c coefficients, defined by

$$C_{ir} = \sum_{j=1}^{n} a_{ij} b_{jr} \quad \text{for} \quad i = 1,2,\ldots m \quad n = 1,2,\ldots,p$$

one can write the m equations as

$$Yi = \sum_{r=1}^{p} C_{ir} Z_r \quad \text{for} \quad 1 = 1,2,\ldots,m$$

Suppose that, instead, one formally had eliminated the x vector by using the vector equation:

$$y = AB_z$$

Since one can consider a vector equation:

$$y = C_z z$$

where the m x p matrix C is defined by:

$$C_{ir} = \sum_{j=1}^{n} a_{ij} b_{jr} \quad \text{for} \quad i = 1,2,\ldots,m \quad n = 1,2,\ldots,p$$

it is at this point obvious that one has indeed defined a matrix product:

$$C = AB$$

where the mp equations constitute the rule for multiplication of A and B. One notes immediately that this product matrix is defined only if the number of columns in A equals the number of rows in B. In general,

$$AB = BA$$

The associative and distributive laws hold for matrix multiplication: i.e.,

$$(AB)C = A(BC) = ABC$$

$$A(B+C) = AB+AC$$

Special Matrices

The null matrix 0 is defined by[11]

$$0 = \begin{bmatrix} 0 \ldots 0 \\ \ldots\ldots \\ 0 \ldots 0 \end{bmatrix}$$

For a null matrix, one has

$$A + 0 = A$$

$$A0 = 0A = 0$$

$$A - A = 0$$

In the scalar case, one knows that the equation $ab=0$ implies that either a or b or both are zero.

The matrix equation $AB=0$ does not imply the same thing, as is exemplified by the product

$$\begin{bmatrix} 1 & 4 \\ 0 & 0 \end{bmatrix} \begin{bmatrix} 4 & 0 \\ -1 & 0 \end{bmatrix} = \begin{bmatrix} 0 & 0 \\ 0 & 0 \end{bmatrix}$$

A matrix is referred to as diagonal if it is square ($m=n$) and if $a_{ij}=0$ for $i \neq j$.

A diagonal matrix of special importance is the identity or unit matrix U:

$$U = \begin{bmatrix} 1 & & & 0 \\ & 1. & & \\ & & \cdot & \\ 0 & & & 1 \end{bmatrix}$$

For the U matrix, one has

$$UA = AU = A$$

$$\underbrace{U\ldots.U}_{n \text{ times}} = U^n = U$$

The transpose A^T of a matrix A is formed by interchanging rows and columns.

Transposition follows the rules:

$$(A+B)^T = A^T + B^T$$

$$(AB)^T = B^T A^T$$

$$(A^T) = A$$

One can now explain better why one earlier denoted the inner vector product of x and y by the symbol $x^T y$.

The reason is simply, that the two vectors x^T and y, viewed as 1 x n and n x 1 matrices, respectively, can be multiplied, and result in the 1 x1 matrix (a scalar) defined by

$$x^T y = \sum_{i=1}^{n} XiYi$$

A matrix is symmetric if it satisfies the equation:

$$A = A^T$$

Determinants and Adjugate (Adjoint) Matrices

Consider the n x n matrix A. Now select an element from each row and column of this matrix and form the following product of n elements:

$$a_{1i}a_{2j}a_{3k}\cdots a_{nr}$$

The set of second subscripts (i,j,k,....,r) is a permutation of the set of integers (1,2,....,n). One can form n! different products of the above type. For example, in the case of 3x3 matrix, the six products are:

$$a_{11}\ a_{22}\ a_{33}$$
$$a_{12}\ a_{23}\ a_{31}$$
$$a_{13}\ a_{21}\ a_{32}$$
$$a_{11}\ a_{23}\ a_{32}$$
$$a_{12}\ a_{21}\ a_{33}$$
$$a_{13}\ a_{22}\ a_{31}$$

One defines now the determinant $|A|$[11]

$$|A| = \sum (\pm) a_{1i}a_{2j}a_{3k}\cdots a_{nr}$$

The sum has to be extended over the n! different permutations of the second subscripts. Each term will be assigned a sign (+ or -) in accordance with the following rule: If the permutation is even, use the + sign; if odd, use the - sign. (A permutation is even or odd depending upon the number of integer interchanges in the set i,j,k,....,r. For example, the sequence 132 has one interchange, (3-2), and is ,therefore, odd, whereas the sequence 231 has two, (2-1) and (3-1), and is thus even.)

For example, for the 3x3 matrix, one finds the determinant, in that case,[11]

$|A| = a_{11}a_{22}a_{33} + a_{12}a_{23}a_{31} + a_{13}a_{21}a_{32} - a_{11}a_{23}a_{32} - a_{12}a_{21}a_{33} - a_{13}a_{22}a_{31}$

The following properties of determinants can be deduced directly from the definition:

$$|A| = |A^T|$$

$$|\lambda A| = |\lambda A^n| \quad \text{n is the order of A}$$

$$|AB| = |A||B|$$

Another useful property is that an interchange of two columns or rows changes the sign of A. One sees that this follows directly from the definition when one realizes that such an interchange changes all odd permutations to even, and vice versa. It follows that A must equal zero if the matrix has two equal rows or columns.

Any element aij of A will appear as a factor in(n-1)! of the n! terms of $|A|$. Each of the n elements of any particular row or column of A is a factor in all the n! terms of $|A|$. It is, therefore, possible to rearrange $|A| = \sum (\pm)\, a_{1i}a_{2j}a_{3k}\ldots a_{nr}$ into either of the following two forms:

$$|A| = \sum_{j=1}^{n} aijAij \text{ or } \sum_{i=1}^{n} aijAij$$

where i can be any row and j any column. The Aij's (the cofactors) will each contain a sum of (n-1)! terms involving those $(n-1)^2$ elements not to be found in row i and column j. The rule for computing Aij is

$A_{ij} = (-1)^{i+j}$ times the determinant of the submatrix formed by deleting row i and column j. The n cofactors A_{i1}, A_{i2}, ...,A_{in} are completely independent of the elements of row i. Therefore, one can replace these elements with those in row $K (K \neq i)$ one has, a matrix with two equal rows and, therefore, zero determinant. One can obtain the relationship

$$\sum_{j=1}^{n} a_{kj} A_{ij} = 0 \quad \text{for } K \neq i$$

similarly:

$$\sum_{i=1}^{n} a_{ik} A_{ij} = 0 \quad \text{for } K \neq j$$

One now defines an nxn matrix A^T having as elements the A_{ji}'s and referred to as the adjugate or adjoint of matrix A.

$$A^T = \begin{bmatrix} A_{11} & A_{21} \cdots & A_{n1} \\ A_{12} & A_{22} \cdots & A_{n2} \\ \cdots & \cdots & \cdots \\ A_{1n} & A_{2n} \cdots & A_{nn} \end{bmatrix}$$

<u>The Matrix Inverse</u>

Consider $\quad y = Ax$

where A is a square matrix of order n having a nonzero determinant. Assume one desires to solve the x_i's. Intuitively, the solution should read $x = Bx$ where B is one as yet unknown n x n matrix. If this solution is substituted back into $y = Ax$ one has $y = ABy$ or if the original y vector is substituted into the solution equation, one has

$$x = BAx$$

In either case, one must require that the B matrix satisfy

$$AB = BA = U$$

A matrix B possessing this property is called the inverse of A and is designated with the symbol $B = A^{-1}$. One can deduce the following properties characterizing the inverse:[11]

$$(AB)^{-1} = B^{-1}A^{-1}$$

$$(A^{-1})^T = (A^T)^{-1}$$

$$(A^{-1})^1 = A$$

Least Squares Estimation

Least squares estimation is a method of forming an estimate based upon redundant measurements of some parameter. In the general case, the measurement is of the form $Z = h(x)+ \varepsilon$ and the distribution of the error terms ε is not known. The principle of least squares states that nature normally tends to minimize the errors which are present in a measurement process, and, therefore, a logical estimate for the parameter x is that value which will yield a minimum sum of squares of the error terms themselves. That is, the error criterion specifies that the loss of function defined as

$$q = \varepsilon_1{}^2 + \varepsilon_2{}^2 + \ldots + \varepsilon_m{}^2 = [Z - h(x)]^T[Z - h(x)]$$

should have a minimum value.

If q is to be minimized by choice of x, the above expression results in a set of nonlinear, simultaneous algebraic equations which has no general solution. But if the measurement is linear and of the form $Z = Hx + \varepsilon$, then the loss function can be written as

$$q = [Z - Hx]^T[Z - Hx] = Z^TZ - 2Z^THx + x^TH^THx$$

The minimization of q is then accomplished by differentiating q with respect to the vector x and equating the result to zero.[10]

$$\frac{\partial q}{\partial x} = \left[\frac{\partial q}{\partial x_1}\ \frac{\partial q}{\partial x_2} \dots \frac{\partial q}{\partial x_n}\right] = -2Z^TH + 2x^TH^TH = 0$$

Solving this equation for x yields the least squares estimate, denoted by $\hat{x}$,

$$\hat{x} = (H^TH)^{-1}H^TZ$$

This concise matrix equation yields a closed form solution for the value of the parameter x which produces the minimum value of the scalar q.

Weighted Least Squares Estimation

If the individual measurement error terms in $Z = Hx + \varepsilon$ are known to have variances which are not identical, then the argument for the error criterion function q in the particular form of[12]

$$q = \varepsilon_1^2 + \varepsilon_2^2 + \dots + \varepsilon_m^2 = [Z - h(x)]^T[Z - h(x)]$$

cannot be made. Instead, a logical approach is to weigh each squared error by a factor which somehow indicates the quality of the associated measurement, so that the loss function is now specified to be

$$q = c_1 \varepsilon_1^2 + C_2 \varepsilon_2^2 + \dots + C_m \varepsilon_m^2$$

where Ci has a large value if the i TH measurement is considered to have low error content, and a small value if the i TH measurement is considered to have a large error content. Such an effect can be incorporated into the previous result by letting $q = [Z - Hx]^T C[Z-Hx]$ where C is a diagonal matrix of the form

$$C = \begin{bmatrix} C_1 & & & & & & \\ & C_2 & & & & & \\ & & \cdot & & & & \\ & & & \cdot & & & \\ & & & & \cdot & & \\ & & & & & \cdot & \\ & & & & & & C_m \end{bmatrix}$$

then

$$q = Z^T CZ - 2Z^T CHx - x^T H^T CHx$$

and

$$\frac{\partial q}{\partial x} = -2Z^T CH + 2x^T H^T CH$$

Solving this for the estimate x yields

$$\hat{x} = [H^T CH]^{-1} H^T CZ$$

which is the weighted least squares estimate of the parameter x. The selection of the weighting functions Ci can be intuitive, although there are systematic approaches to their selection.

Linear Programm.ng

This procedure is used to optimize a linear function subject to linear constraints. The general problem is of the form:

$$\max(\min)\ cX$$

$$\text{subject to:} \quad Ax \;\begin{matrix}\leq\\=\\\geq\end{matrix}\; b$$

$$li \leq xi \leq Ui \quad i = 1,2,\ldots,n$$

where

A is an mxn matrix of coefficients

b is an mx1 matrix of constants

c is an nx1 matrix of coefficients

x is an nx1 matrix of variables

li is a lower bound on xi and

Ui is an upper bound on xi

Consider the example

$$f(x) = c_1x_1 + c_2x_2 + c_3x_3$$

$$a_{11}x_1 + a_{12}x_2 + a_{13}x_3 \leq b_1$$

$$a_{12}x_1 + a_{22}x_2 + a_{23}x_3 \leq b_2$$

$$x_1 \geq 0 \qquad x_2 \geq 0 \qquad x_3 \geq 0$$

Applying the Kuhn-Tucker conditions to this yields the Lagrange function[12]

$$\begin{aligned} F(x_1,x_2,x_3\lambda_1,\lambda_2,\lambda_3,\lambda_4,\lambda_5) = {} & c_1x_1 + c_2x_2 + c_3x_3 \\ & +\lambda_1(a_{11}x_1 + a_{12}x_2 + a_{13}x_3) \\ & +\lambda_2(a_{21}x_1 + a_{22}x_2 + a_{23}x_3) \\ & +\lambda_3x_1 + \lambda_4x_2 + \lambda_5x_3 \end{aligned}$$

The Kuhn-Tucker conditions are then

I. $$\frac{\partial F}{\partial x} = 0; \quad \begin{aligned} & c_1 + a_{11}\lambda_1 + a_{21}\lambda_2 + \lambda_3 = 0 \\ & c_2 + a_{12}\lambda_1 + a_{22}\lambda_2 + \lambda_4 = 0 \\ & c_3 + a_{13}\lambda_1 + a_{23}\lambda_2 + \lambda_5 = 0 \end{aligned}$$

II. $\lambda i[gi(x)-bi] = 0;\ \lambda_1(a_{11}x_1 + a_{12}x_2 + a_{13}x_3) = 0$

$$\lambda_2(a_{21}x_1 + a_{22}x_2 + a_{23}x_3) = 0$$

$$\lambda_3 x_1 = 0$$

$$\lambda_4 x_2 = 0$$

$$\lambda_5 x_3 = 0$$

III. $\lambda i < 0$ for max $i = 1,\ldots,5$

$\lambda i > 0$ for min $i = 1,\ldots,5$

IV. $gi(x) \leq bi;\quad a_{11}x_1 + a_{12}x_2 + a_{13}x_3 \leq b_1$

$$a_{21}x_1 + a_{22}x_2 + a_{23}x_3 \leq b_2$$

$$x_1 \geq 0 \qquad x_2 \geq 0 \qquad x_3 \geq 0$$

From condition I, it can be seen that there are no values of the λ's which can satisfy this equation, without two or more of them being zero. From condition II, this fact is turn implies that the solution must lie on at least two boundaries. Since the constraints are linear and in the form of planes in the three-dimensional (x_1, x_2, x_3) space, it is also implied that the solution must lie at the intersection of constraint planes.

In general, solutions to problems of this type are constrained to lie at intersections of constraint planes in the multidimensional x space, and this fact serves as the basis for a specialized solution technique known as the simplex method. A problem of the general form given is known as a linear programming problem and can be solved most efficiently by the simplex method, which systematically searches through all constraint plane intersections for a minimum or a maximum.

Chapter III

Model Concepts

The experience of the 1970s has shown the importance to utilities of developing a flexible and diverse management strategy that will help them achieve their objectives in an increasingly uncertain and competitive environment. A key challenge of the 1980s will be to integrate effectively traditional supply side planning options with the emerging concept of deliberately modifying utility load shapes. Recognizing the importance of modifying utility load shapes and the need to consider strategic load growth as well as conservation and load management, load impact or load sensitivity studies can be undertaken that are consistent with utility program design and marketing strategies. Broadly defined, the objective of this study is to provide an operational procedure to assist utilities plan, evaluate and implement modification of load shapes. Initially it's important to understand the utility customer hierarchy. This is illustrated in Figure 1. The most general representation of the utility's load shape is the customer class. For most utilities, the classes are residential, commercial, industrial, and other. These are all encompassing groups that do not focus on any specific customer. For example, the residential class includes totally electric homes, those with electric water heaters, and those with only lighting. Much data is available for these customer classes which is collected at the main substations through the use of various metering equipment. The specific format and data available will be discussed later when the model is defined.

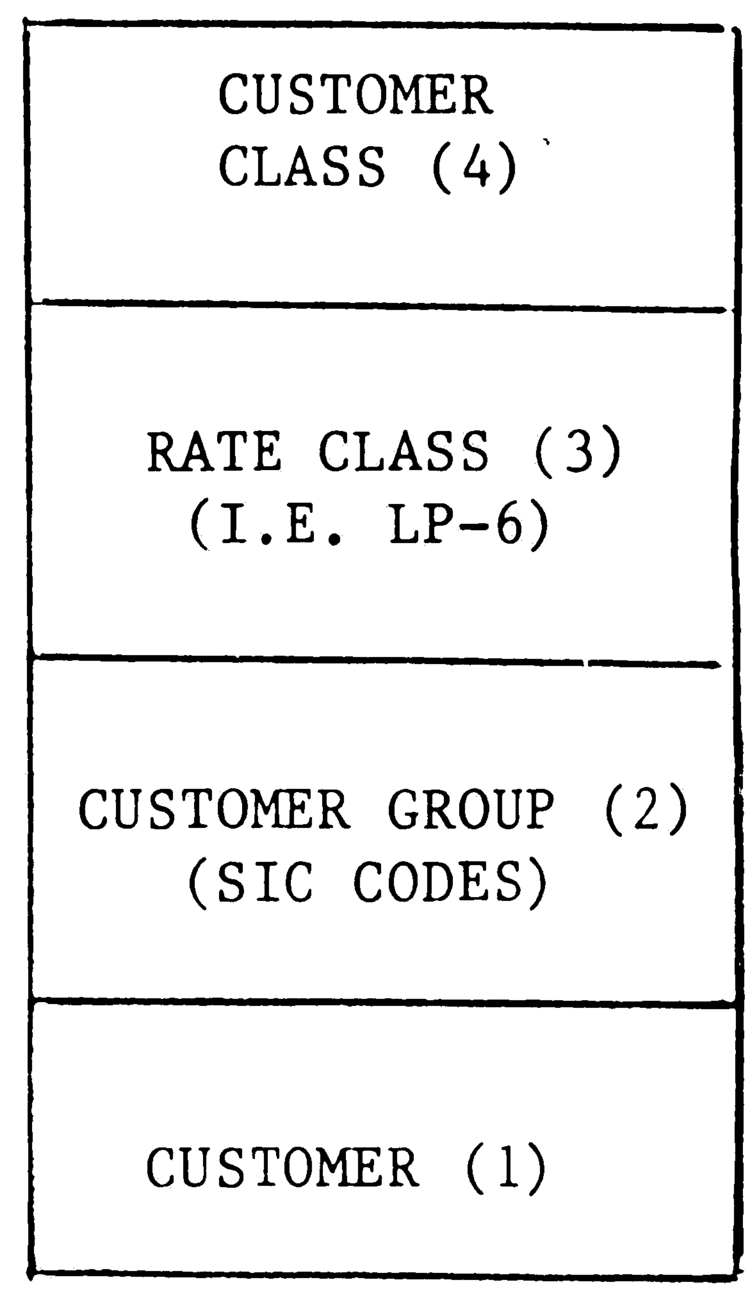


FIGURE 1

CUSTOMER HIERARCHY

The rate class is a further refinement of the customer class. In broad terms, this class groups, for example, all electrically heated homes into one revenue rate. i.e. RS, GH, GL, LP, Etc. The customer group (SIC Codes) are the next refinement to the rate class. They attempt to classify small customer groups into an industry accepted customer class. (Figure 2) These codes identify the group title (general residential, textile-mill products, cement, etc.) the SIC category and the customer class and rate class. Finally, the customer represents the highest refinement in the customer hierarchy. This represents the specific end-user. Little data is available for these customers since collection requires a meter for each one. Large customers, such as the steel industry, does have metering but this is the exception.

Title	(1) SIC CODE AND MARKET SECTOR Codes Oper. Sum.	Components	(2) CUSTOMER CLASS Title
General Residential	GRS	Rev. Codes 03, 04	General Residential
Electrically Heated Homes	EHH	Rev. Codes 01, 02	Elec. Heated Homes
Wholesale & Retail Trade	W&RT	SIC 50-59	Commercial
Financial & Personal Service	F&PS	SIC 60-89	
Small Commercial	SC	Rev. Codes 22,23 minus W&RT,FP&S, OC	
Textile-Mills Products	TEX	SIC 22	Industrial
Apparel	APP	SIC 23	
Coal Mining	CM	SIC 11, 12	
Cement	CEM	Rev. Code 27	
Steel Manufacturing	STL	Rev. Code 29	
Other Primary Metals	OPM	SIC 33 minus Rev. Code 29	
Non-Electric Machinery	NEM	SIC 35	
Other Metal Products	OMP	SIC 10, 19, 34, 37, 38	
Food & Kindred Products	F&KP	SIC 20	
Printing & Publishing	P&P	SIC 27	
Chemicals & Allied Products	CHEM	SIC 28	
Other General Industry	OGI	SIC 13,14,21,24,25,26,29,30,31,32,39 minus Rev. Code 27	
Public Authorities	PA	Rev. Codes 40, 50	Other
Railroads	RR	Rev. Code 60	
Borderline	RES BL	Rate Code 54	
Resale 12KV	RES 12KV	Rate Codes 74,78,84,71,75,76,72,81,85	
Resale 66KV	RES 66KV	Rate Codes 86, 87, 83, 80, 77, 88	
UGI	UGI	Rate Code 82	

FIGURE 2

SIC CATEGORIES

Much work has been done evaluating load shaping for both the customer and customer group. This study will focus, however, on the general load shapes. (Customer Class) Concept of Load Shaping

Figure 3 reflects the numerous approaches to load shaping. This is a delicate balance for the utility to meet customer needs while controlling load growth and peaks which equates to controlling capital expenditures. Ideally, the utility would like to maintain the area under the load curve for a given time frame (i.e. 24 hour period). This generally promotes optimal use of available generation.

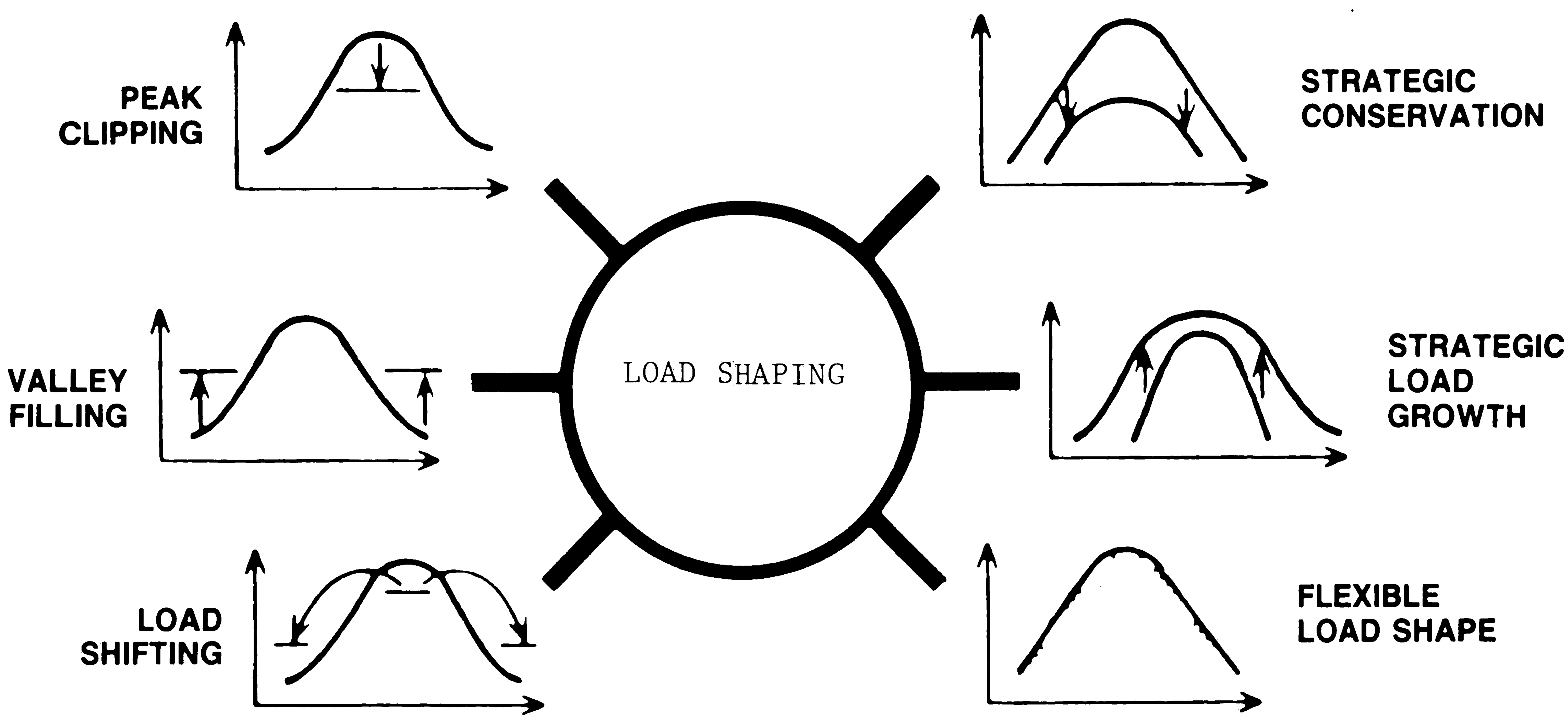


FIGURE 3

LOAD SHAPE OBJECTIVES

So, why is load shaping important?

- o It can eliminate costly peaks and the need to start up additional generation.
- o If the area under the curve (net required load) can be maintained constant, it can actually reduce the number of generation units required.
- o It can increase the utility's revenues.
- o It can reduce the overall cost to the customer.

The load shaping options include:

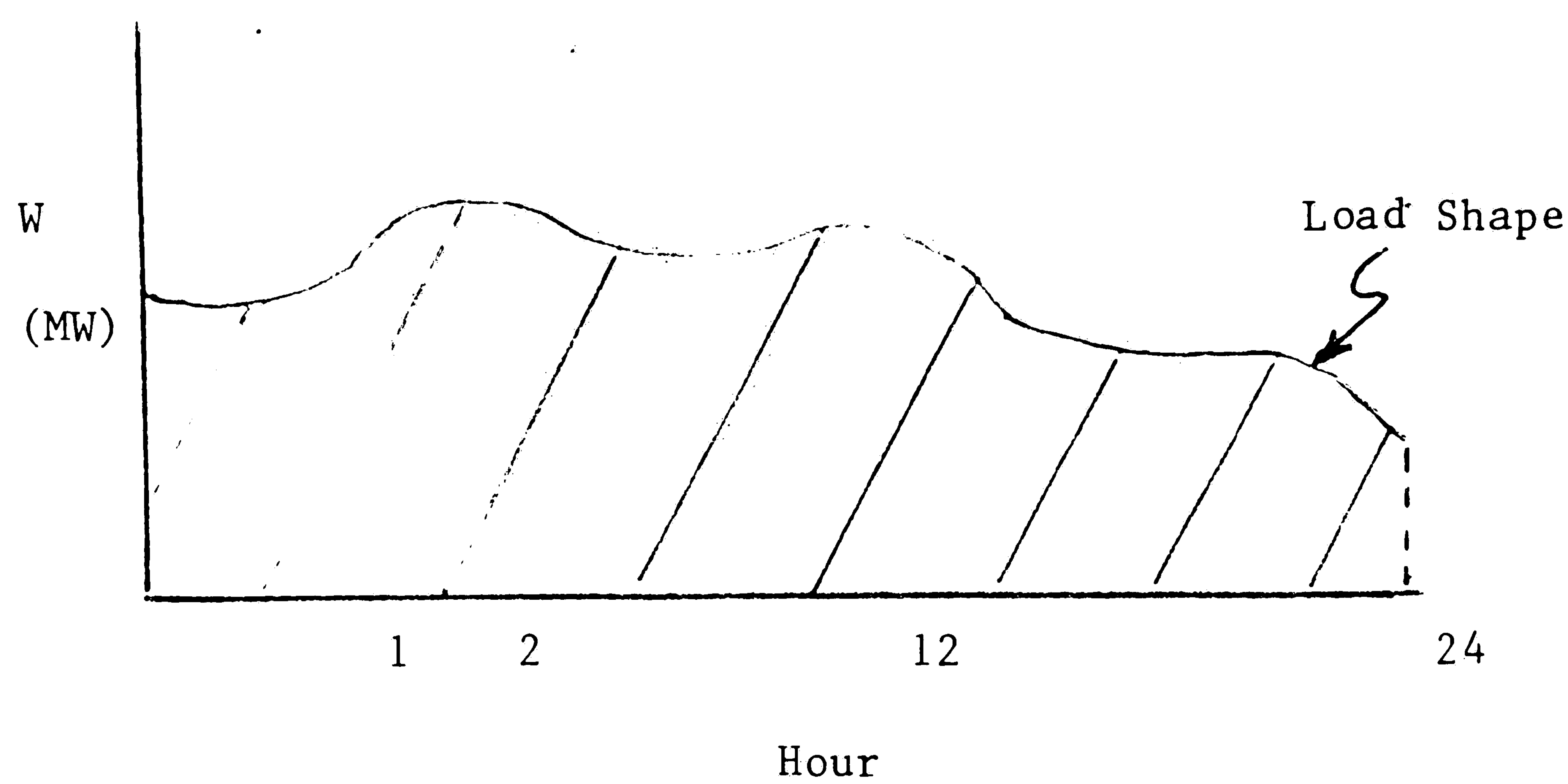
- o Peak Clipping - Reducing the curve peaks at certain times of the day or year.
- o Valley Filling - This approach basically accepts the peaks but promotes increasing the load during off-peak hours.
- o Load Shifting - This attempts to shift use during peak hours to other times of the day or year.
- o Strategic Conservation - As the name implies, this promotes conservation which does not necessarily change the load shape, but does have a reducing effect to the curve. That is, the curve will shift down.
- o Strategic Load Growth - This is the opposite approach to strategic conservation. Overall, the curve will move up.

o Flexible Load Shape - This approach accepts any load shape. This study began by first collecting and analyzing a utilities data for customer classes.

The general problem statement is

$$\sum_{i=1}^{24} Wi \qquad Wi = \text{The given load in megawatts for hour i.}$$

The load shape assumes the area under the curve is fixed and generally will have the following form.



The customer cost for this energy will be

$$\text{Cost} = \sum_{i=1}^{24} Ci\ Wi \qquad \text{(Objective Function)}$$

Ci = The various rate schedules (Price Coefficient)

Wi = The given load in Megawatts for hour i

The overall objective, to be performed later, will be to minimize this function for the customer and to maximize utility revenues.

As discussed in Figure 1, the customer groups are:

Residential

Commercial

Industrial

Other

The overall load curve will be of the form:

$$Y(K) = \sum_{i=1}^{4} \alpha i \; Yi(K) + Ui(K)$$

Y(K) = The overall or total load at hour K.

α i = Load Factor for customer group i.

Yi(K) = Total load for customer group i at hour K.

Ui(K) = Random error term for customer group i at hour K.

To compare the customer load groups to the total load for a good match;

$$\sum_{i=1}^{4} \alpha i(K) Yi(K) + Ui(K) = Y(K)$$

Weighted Least Square Problem Foundation

The objectives of this analysis are to:

1. Compare customer load groups to the total load with actual utility data and verify a good match for the overall model.
2. Examine the effect on sensitivity of load group characteristics by varying the sensitivity factor alpha (α) and illustrating the

impact on total load and the potential for benefit of shifting a given load group.

3. Optimize the tariff of an actual utility to analyze what the best load group mix should be based on these existing tariffs.

4. Provide conclusions and recommendations for a marketing strategy.

Objectives 1 and 2 were performed using computer procedures that perform regression analysis, which is the fitting of an equation to a set of values. The equation predicts a response variable from a function of regressor variables and parameters, adjusting the parameters such that a measure of fit is optimized.

For example, the equation for the ith observation might be:

$$Yi = \beta o + \beta iXi + \varepsilon i$$

Where Yi is the response variable, Xi is a regressor variable, βo and $\beta 1$ are unknown parameters to be estimated, and εi is an error term.

Regression is often used in an exploratory fashion to look for empirical relationships. In this case, to look for the relation between the time of day and the Megawatt hours predicted for a given load group.

The method used to estimate the parameters is to minimize the sum of squares of the differences between the actual response value and the value predicted by the equation. The estimates are called least-squares estimates and the criterion value is called the sum-of-squares error:

$$SSE = \sum (Yi - bo - b_1 xi)^2$$

Where bo and b_1 are the values for βo and $\beta 1$ that minimize SSE.

This procedure (NLIN) implements iterative methods that attempt to find lease-squares estimates for nonlinear models. One must specify parameter names and starting values, expressions for the model and expressions for derivatives of the model with respect to the parameters. Figure 4 illustrates the general form of the model equations.

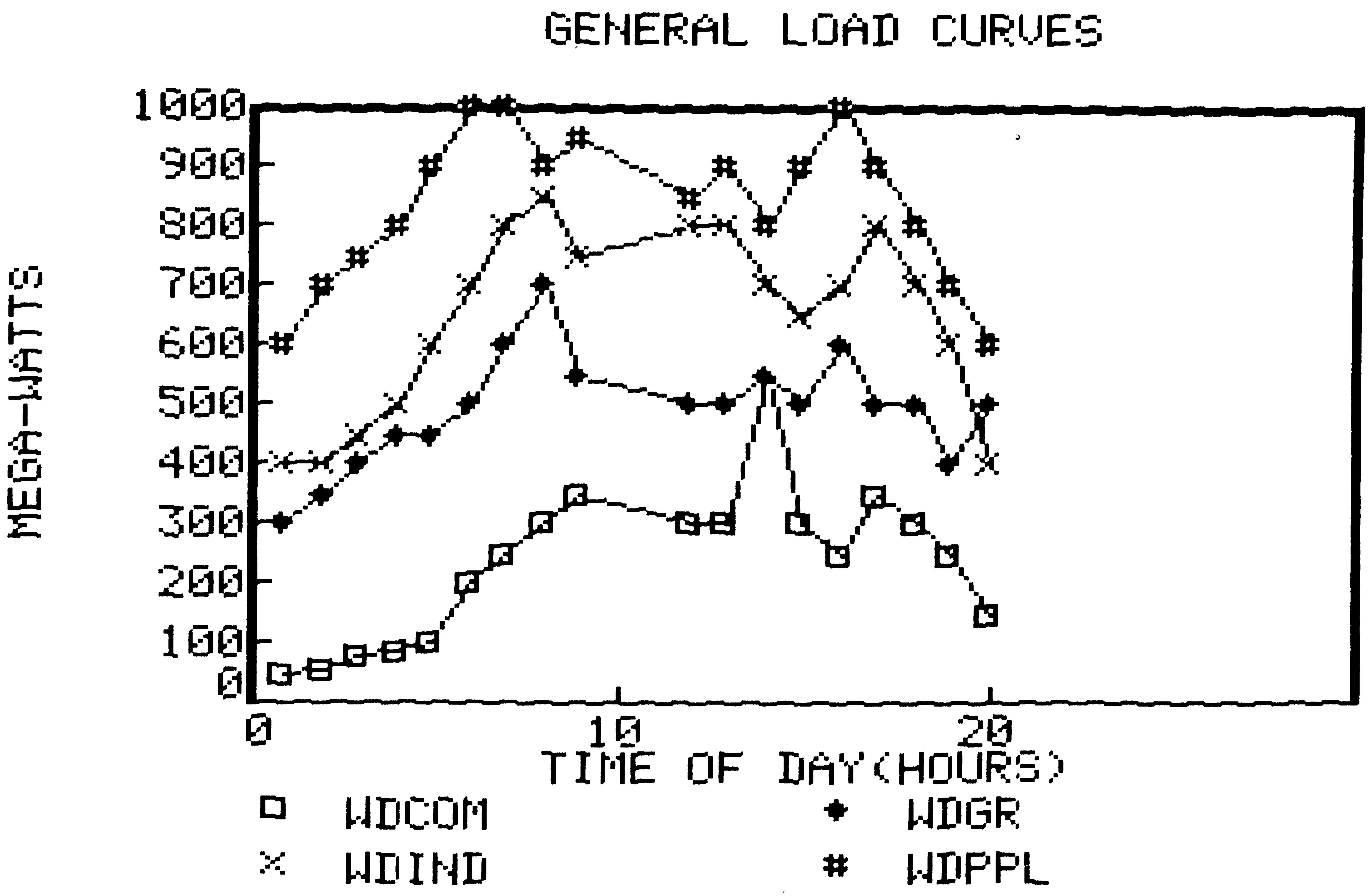

GENERAL LOAD CURVES
MEGA-WATTS
1000
900
800
700
600
500
400
300
200
100
0
0
10
20
TIME OF DAY(HOURS)
WDCOM
WDGR
WDIND
WDPPL

FIGURE 4

WDGR = Week-day general residential curve.

WDCOM = Week-day commercial curve.

WDIND = Week-day industrial curve.

WDOTH = Week-day other curve.

WDPPL = Week-day total load curve.

Computational Method

For this nonlinear model,

$$Y = F(\beta_o, \beta_1, \ldots. \beta_K, X1, X2 \ldots. Xn) + \varepsilon = F(B) + \varepsilon,$$

the nonlinear normal equations are:

$X'F(B) = X'Y$

where

$$X = \frac{\partial F}{\partial B}$$

In the nonlinear situation, both X and F(B) are functions of B, and a closed-form solution generally does not exist. A starting value for B is chosen and continually improved until the error sum of squares $\varepsilon' \varepsilon$ (SSE) is minimized.

The iterative techniques (NLIN) uses are similar to a series of linear regressions involving the matrix x evaluation for the current values of β and $Y=Y-\hat{Y}$, where $\hat{Y} = F(B)$ are the predicted values evaluated for the current values of β. The iterative process begins at some point β_o. Then X and Y are employed to compute a Δ such that:

$$SSE(\beta_o + \Delta) < SSE(\beta_o).$$

Delta (Δ) is computed using the Taylor series $F(B) = F(Bo) + X(B-Bo) + \ldots$

where $X = \frac{\partial F}{\partial B}$ is evaluated at $B=Bo$.

Substituting the first two terms of this series into the normal equations:

$$X''F(B) = X'Y$$

$$X'(F(Bo) + X(B-Bo)) = X'Y$$

$$X'F(Bo) + X'X(B-Bo) = X'Y$$

$$(X'X)(B-Bo) = X'Y - X'F(Bo)$$

$$(X'X)\ \Delta = X'Y \text{ where } \Delta = (X'X)^{-1}X'Y$$

Model

The specific model equation used is:

$$WDPPL = \alpha 1WDGR + \alpha 2WDCOM + \alpha 3\ WDIND + \alpha 4\ WDOTH$$

Where $\alpha 1,2,3,4$ = Sensitivity coefficients for each load group. (Load Factor)

WDGR = Weekday general residential load in Megawatts.

WDCOM = Weekday commercial load in Megawatts.

WDIND = Weekday industrial load in Megawatts.

WDOTH = Weekday all other load in Megawatts.

WDPPL = Weekday total load in Megawatts.

α was allowed to vary from 0.5 to 1.0.

The derivatives used are:

$\partial \alpha 1$ = WDOR

$\partial \alpha 2$ = WDOM

$\partial \alpha 3$ = WDIND

$\partial \alpha 4$ = WDOTH

The computer program and data points used are presented in Chapter 4 along with the specific results. This initial study indicated:

1. The WDOTH load group is small in magnitude and has a fairly linear response. Overall it has little effect on the sensitivity of the total load. It would probably be of little value in a marketing strategy.
2. Adjusting the sensitivity factor (α) for WDGR, WDCOM, and WDIND illustrated significant effect on the total load and demonstrated the ability to levelize the total load. It appears, emphasis should be placed on the general residential and industrial load groups to maximize a leveling of the total load.

The next step in this analysis involved a linear programming problem to optimize revenues based on existing tariffs. The (LP) procedure was used to optimize a linear fu.ction subject to linear constraints. Specifically, LP solves the general linear programming problem of the form:

$$\mathrm{MAX(MIN)}\,C'X$$

$$\text{Subject to} \quad AX \begin{matrix} \leq \\ = \\ \geq \end{matrix} b$$

$$li \leq Xi \leq Ui \quad i=1,\ldots,n$$

Where

A is an MXN matrix of coefficients

b is an MX1 matrix of right-hand side constants

c is an NX1 matrix of price coefficients

X is an NX1 matrix of structural variables

li is a lower bound on Xi, and

Ui is an upper bound on Xi

Rate schedules (tariffs) were analyzed for the residential, commercial, and industrial load groups. Generically, the tariffs are of the form:

$$C + Ax = b$$

where C is a fixed customer charge

A is a designated price coefficient in cents per Kilowatt hour

X is the kilowatt hours used by the customer.

Since the LP procedure is not capable of dealing with the fixed customer charge, the programming results were manually corrected to compensate for this. The specific program and data points are presented in Chapter 4.

In general, the results revealed:

1. Variation of the tariff structure can have a dramatic effect on the optimization problem. Large shifts in the load groups would have to realized to satisfy optimization.

2. Large shifts in the industrial load group will have a major impact on the total load curve.

3. The industrial load group seems to have significant potential for increasing revenues by a change in the tariff structure and potential for a significant change (levelizing effect) on the total load curve.

Tariff Sensitivity Analysis

Right-hand-side sensitivity analysis can be used to examine the sensitivity of the solution X^{OPT} of problem (LP) to changes in the right-hand-side constants. Since X^{OPT} is feasible in (LP), it can be written as:

$$X^{OPT} = B^{-1}b$$

for basis matrix B. Also, $B^{-1}b$ satisfies $\ell \leq B^{-1}b \leq u$ where ℓ is a column vector of the lower bounds on the structural variables, and u is a column vector of the upper bounds on the structural variables.

For each right-hand-side change vector r identified, LP finds an interval (ϕ MIN, ϕ MAX) such that

$$\ell \leq B^{-1}(b+\phi r) \leq u$$

for all $\phi \in$ (ϕ MIN, ϕ MAX). Furthermore, since changes in the right-hand-side do not affect the reduced costs, the vectors

$$XMIN = B^{-1}(b + \phi MIN r)$$

$$XMAX = B^{-1}(b + \phi MAX r)$$

are optimal in the problems

$\text{MAX(MIN) } C'X$

subject to $AX \begin{smallmatrix}\leq\\=\\\geq\end{smallmatrix} b + \phi \text{ MIN } \Gamma$

$\ell i \leq Xi \leq Ui \quad i = 1,\ldots,n$

and

$\text{MAX(MIN)} C' X$

subject to $Ax \begin{smallmatrix}\leq\\=\\\geq\end{smallmatrix} b + \phi \text{ MAX } \Gamma$

$\ell i \leq Xi \leq Ui \quad i = 1,\ldots.,n$

respectfully.

Cost Sensitivity Analysis

LP can also be used to examine the sensitivity of the solution X^{OPT} of problem (LP) to changes in the cost coefficients. Since X^{OPT} is feasible in (LP), it can be written as

$$X^{OPT} = B^{-1}b$$

for basis matrix B.

Furthermore, since X^{OPT} is feasible in (LP), the reduced costs at optimality satisfy

$$(C_N - C_B B^{-1}N)i \geq (\leq) 0$$

if the nonbasic variable in column i is at its upper bound, and

$$(C_N - C_B B^{-1}N)i \leq (\geq) 0$$

if the nonbasic variable in column i is at its lower bound. N is the matrix comprised of the nonbasic columns of A, and C_N, and C_B is a partition of the vector of cost coefficients into basic and nonbasic components.

For each cost coefficient change vector r, LP finds an interval (ϕ MIN, ϕ MAX) such that

$$[(C + \phi r)_N - (C + \phi r)_B B^{-1} N) i \geq (\leq) 0$$

if the nonbasic variable in column i is at its upper bound, and

$$(C + \phi r)_N - (C + \phi r)_B B^{-1} N) i \leq (\geq) 0$$

if the nonbasic variable in column i is at its lower bound, for all $\phi \varepsilon (\phi \text{ MIN}, \phi \text{ MAX})$.

Since changes in the cost coefficients do not affect feasibility, for $\phi (\phi \text{ MIN}, \phi \text{ MAX}) X^{OPT}$ is optimal in

$$\text{MAX(MIN) } (C + \phi r)' X$$

subject to $AX \begin{matrix} \leq \\ = \\ \geq \end{matrix} b$

$$\ell i \leq Xi \leq Ui \quad i = 1, \ldots, n$$

The sensitivity analysis offered interesting results and much insight into the concepts of tariff reform. Changes to the pricing and "blocks" of power at a given price can have a significant effect on both the load curve and the utility revenues. Specific results are covered in Chapter 4.

Chapter IV

CASE STUDIES

Study 1

This first study was a least squares estimation to compare customer load groups to the total load with actual utility data to verify a good match for the overall model. The data used for this analysis is that from an actual utility. The data bases are quite extensive, so a "typical" 24 hour period was selected for each load group. Tables 1 through 5 show each data set used. The data is organized by the observation and hour, season, weekday and weekend per unit value, year, and the unitized or adjusted totals in megawatt hours. The load groups are:

GR = General Residential

IND = Industrial

COM = Commercial

OTH = Other

PPL = Total Load

Table 6 is the program listing that was used to generate the output.

"WDGR DATA"

TABLE 1

PERM.USIMGR

OBS	HOUR	SEASON	WDGR	WEGR	YEAR	ADJF_GR	ADJWDGR	ADJWEGR
1	100	FLLSPR	0.49019	0.555476	1984	768.189	376.557	426.710
2	200	FLLSPR	0.45239	0.482821	1984	768.189	347.518	370.897
3	300	FLLSPR	0.42773	0.446927	1984	768.189	328.579	343.324
4	400	FLLSPR	0.41944	0.438431	1984	768.189	322.211	336.798
5	500	FLLSPR	0.43670	0.428756	1984	768.189	335.471	329.366
6	600	FLLSPR	0.51298	0.460963	1984	768.189	394.066	354.107
7	700	FLLSPR	0.67626	0.521627	1984	768.189	519.492	400.708
8	800	FLLSPR	0.78004	0.665274	1984	768.189	599.218	511.056
9	900	FLLSPR	0.75746	0.727398	1984	768.189	581.869	558.779
10	1000	FLLSPR	0.71616	0.800644	1984	768.189	550.146	615.046
11	1100	FLLSPR	0.72781	0.837289	1984	768.189	559.094	643.196
12	1200	FLLSPR	0.74164	0.878640	1984	768.189	569.721	674.961
13	1300	FLLSPR	0.69161	0.863545	1984	768.189	531.288	663.365
14	1400	FLLSPR	0.65764	0.813351	1984	768.189	505.191	624.807
15	1500	FLLSPR	0.63750	0.788682	1984	768.189	489.724	605.857
16	1600	FLLSPR	0.70430	0.773841	1984	768.189	541.035	594.456
17	1700	FLLSPR	0.85392	0.825381	1984	768.189	655.969	634.048
18	1800	FLLSPR	1.00000	0.916830	1984	768.189	768.189	704.298
19	1900	FLLSPR	0.97410	0.963143	1984	768.189	748.295	739.875
20	2000	FLLSPR	0.94513	0.941405	1984	768.189	726.037	723.176
21	2100	FLLSPR	0.91914	0.896081	1984	768.189	706.077	688.359
22	2200	FLLSPR	0.89016	0.849898	1984	768.189	683.812	652.882
23	2300	FLLSPR	0.80619	0.754833	1984	768.189	619.302	579.854
24	2400	FLLSPR	0.60755	0.619137	1984	768.189	466.712	475.614
25	100	SUMMER	0.54548	0.572177	1984	816.649	445.466	467.268
26	200	SUMMER	0.48020	0.522429	1984	816.649	392.156	426.641
27	300	SUMMER	0.45982	0.473075	1984	816.649	375.513	386.336
28	400	SUMMER	0.44663	0.448715	1984	816.649	364.740	366.443
29	500	SUMMER	0.43804	0.439936	1984	816.649	357.722	359.273
30	600	SUMMER	0.50230	0.458560	1984	816.649	410.205	374.482
31	700	SUMMER	0.59967	0.497904	1984	816.649	489.718	406.612
32	800	SUMMER	0.64095	0.607100	1984	816.649	523.431	495.787
33	900	SUMMER	0.66560	0.707512	1984	816.649	543.563	577.789
34	1000	SUMMER	0.71101	0.746692	1984	816.649	580.646	609.785
35	1100	SUMMER	0.74445	0.771874	1984	816.649	607.956	630.350
36	1200	SUMMER	0.78465	0.853735	1984	816.649	640.780	697.201
37	1300	SUMMER	0.77059	0.874446	1984	816.649	629.299	714.115
38	1400	SUMMER	0.72809	0.826497	1984	816.649	594.597	674.957
39	1500	SUMMER	0.75766	0.791214	1984	816.649	618.745	646.144
40	1600	SUMMER	0.80981	0.814933	1984	816.649	661.326	665.514
41	1700	SUMMER	0.93833	0.862953	1984	816.649	766.283	704.729
42	1800	SUMMER	1.00000	0.926917	1984	816.649	816.649	756.965
43	1900	SUMMER	0.96389	0.906577	1984	816.649	787.158	740.355
44	2000	SUMMER	0.87451	0.844473	1984	816.649	714.166	689.637
45	2100	SUMMER	0.89275	0.835569	1984	816.649	729.059	682.366
46	2200	SUMMER	0.91339	0.889308	1984	816.649	745.915	726.253
47	2300	SUMMER	0.84479	0.803957	1984	816.649	689.901	656.551
48	2400	SUMMER	0.68865	0.662702	1984	816.649	562.387	541.194
49	100	WINTER	0.50540	0.550364	1984	951.626	480.954	523.741
50	200	WINTER	0.45053	0.482920	1984	951.626	428.740	459.559
51	300	WINTER	0.42897	0.447803	1984	951.626	408.215	426.141

"WDIND DATA"

TABLE 2

SAS

OBS	HOUR	SEASON	WDIND	WEIND	YEAR	ADJF_IND	ADJWDIND	ADJWEIND
1	100	FLLSPR	0.71175	0.587961	1984	1312.35	934.06	771.612
2	200	FLLSPR	0.69277	0.570394	1984	1312.35	909.16	748.557
3	300	FLLSPR	0.68531	0.562709	1984	1312.35	899.37	738.472
4	400	FLLSPR	0.66380	0.553430	1984	1312.35	871.14	726.295
5	500	FLLSPR	0.67681	0.547721	1984	1312.35	888.21	718.803
6	600	FLLSPR	0.70080	0.538675	1984	1312.35	919.70	706.930
7	700	FLLSPR	0.75275	0.526853	1984	1312.35	987.87	691.416
8	800	FLLSPR	0.87721	0.558502	1984	1312.35	1151.21	732.951
9	900	FLLSPR	0.94488	0.577893	1984	1312.35	1240.01	758.399
10	1000	FLLSPR	0.97189	0.614626	1984	1312.35	1275.46	806.605
11	1100	FLLSPR	0.98816	0.649712	1984	1312.35	1296.82	852.650
12	1200	FLLSPR	0.97943	0.631858	1984	1312.35	1285.36	829.219
13	1300	FLLSPR	0.96430	0.619269	1984	1312.35	1265.50	812.698
14	1400	FLLSPR	1.00000	0.624662	1984	1312.35	1312.35	819.776
15	1500	FLLSPR	0.95636	0.605549	1984	1312.35	1255.08	794.693
16	1600	FLLSPR	0.92493	0.601517	1984	1312.35	1213.83	789.401
17	1700	FLLSPR	0.89796	0.598061	1984	1312.35	1178.44	784.866
18	1800	FLLSPR	0.86012	0.574093	1984	1312.35	1128.79	753.412
19	1900	FLLSPR	0.85018	0.585092	1984	1312.35	1115.73	767.847
20	2000	FLLSPR	0.84057	0.594712	1984	1312.35	1103.12	780.471
21	2100	FLLSPR	0.82935	0.609540	1984	1312.35	1088.40	799.930
22	2200	FLLSPR	0.80856	0.591212	1984	1312.35	1061.12	775.878
23	2300	FLLSPR	0.77224	0.566623	1984	1312.35	1013.45	743.609
24	2400	FLLSPR	0.73424	0.581661	1984	1312.35	963.58	763.344

"WDCOM DATA"

TABLE 3

SAS

OBS	HOUR	SEASON	WDCOM	WECOM	YEAR	ADJF_COM	ADJWDCOM	ADJWECOM
1	100	FLLSPR	0.50495	0.461851	1984	1096.22	553.53	506.288
2	200	FLLSPR	0.49634	0.446789	1984	1096.22	544.10	489.777
3	300	FLLSPR	0.48485	0.440789	1984	1096.22	531.50	483.200
4	400	FLLSPR	0.48005	0.431615	1984	1096.22	526.24	473.143
5	500	FLLSPR	0.49000	0.420313	1984	1096.22	537.15	460.754
6	600	FLLSPR	0.52025	0.427113	1984	1096.22	570.31	468.208
7	700	FLLSPR	0.58218	0.436057	1984	1096.22	638.19	478.012
8	800	FLLSPR	0.76735	0.453148	1984	1096.22	841.18	496.747
9	900	FLLSPR	0.91594	0.489535	1984	1096.22	1004.06	536.635
10	1000	FLLSPR	0.96549	0.551557	1984	1096.22	1058.38	604.625
11	1100	FLLSPR	1.00000	0.568207	1984	1096.22	1096.22	622.878
12	1200	FLLSPR	0.97575	0.559541	1984	1096.22	1069.64	613.378
13	1300	FLLSPR	0.94156	0.542758	1984	1096.22	1032.15	594.979
14	1400	FLLSPR	0.98650	0.537289	1984	1096.22	1081.42	588.984
15	1500	FLLSPR	0.95506	0.521489	1984	1096.22	1046.95	571.664
16	1600	FLLSPR	0.87268	0.516581	1984	1096.22	956.64	566.283
17	1700	FLLSPR	0.81339	0.506176	1984	1096.22	891.66	554.878
18	1800	FLLSPR	0.72608	0.495757	1984	1096.22	795.94	543.456
19	1900	FLLSPR	0.70022	0.501081	1984	1096.22	767.59	549.293
20	2000	FLLSPR	0.74032	0.526397	1984	1096.22	811.55	577.045
21	2100	FLLSPR	0.71431	0.531321	1984	1096.22	783.04	582.442
22	2200	FLLSPR	0.65835	0.511942	1984	1096.22	721.70	561.198
23	2300	FLLSPR	0.61178	0.481337	1984	1096.22	670.64	527.649
24	2400	FLLSPR	0.55446	0.470492	1984	1096.22	607.81	515.760

"WDOTH DATA"

TABLE 4

SAS

OBS	HOUR	SEASON	WDOTH	WEOTH	YEAR	ADJF_OTH	ADJWDOTH	ADJWEOTH
1	100	FLLSPR	0.62650	0.635266	1984	166.631	104.394	105.855
2	200	FLLSPR	0.58015	0.580450	1984	166.631	96.672	96.721
3	300	FLLSPR	0.54155	0.561995	1984	166.631	90.239	93.646
4	400	FLLSPR	0.56022	0.552104	1984	166.631	93.350	91.997
5	500	FLLSPR	0.56992	0.532762	1984	166.631	94.967	88.775
6	600	FLLSPR	0.60003	0.523220	1984	166.631	99.983	87.184
7	700	FLLSPR	0.67827	0.453126	1984	166.631	113.020	75.505
8	800	FLLSPR	0.82330	0.420357	1984	166.631	137.187	70.044
9	900	FLLSPR	0.92653	0.506061	1984	166.631	154.388	84.325
10	1000	FLLSPR	0.96526	0.590653	1984	166.631	160.841	98.421
11	1100	FLLSPR	0.98363	0.610708	1984	166.631	163.902	101.763
12	1200	FLLSPR	0.94962	0.620702	1984	166.631	158.235	103.428
13	1300	FLLSPR	0.88628	0.601120	1984	166.631	147.682	100.165
14	1400	FLLSPR	0.90120	0.542568	1984	166.631	150.167	90.408
15	1500	FLLSPR	0.85697	0.495857	1984	166.631	142.798	82.625
16	1600	FLLSPR	0.79180	0.480996	1984	166.631	131.938	80.149
17	1700	FLLSPR	0.80614	0.514058	1984	166.631	134.328	85.658
18	1800	FLLSPR	0.83985	0.569583	1984	166.631	139.944	94.910
19	1900	FLLSPR	0.87186	0.655285	1984	166.631	145.279	109.191
20	2000	FLLSPR	0.93626	0.740668	1984	166.631	156.010	123.418
21	2100	FLLSPR	1.00000	0.780627	1984	166.631	166.631	130.076
22	2200	FLLSPR	0.91456	0.764984	1984	166.631	152.394	127.470
23	2300	FLLSPR	0.77361	0.711486	1984	166.631	128.908	118.555
24	2400	FLLSPR	0.74303	0.679555	1984	166.631	123.812	113.235

"WDPPL DATA"

TABLE 5

SAS

OBS	HOUR	SEASON	WDPPL	WEPPL	YEAR	ADJF_PPL	ADJWDPPL	ADJWEPPL
1	100	FLLSPR	0.64278	0.601651	1984	3500.47	2250.03	2106.06
2	200	FLLSPR	0.62556	0.572590	1984	3500.47	2189.76	2004.33
3	300	FLLSPR	0.61157	0.557802	1984	3500.47	2140.79	1952.57
4	400	FLLSPR	0.60525	0.552799	1984	3500.47	2118.67	1935.05
5	500	FLLSPR	0.61729	0.546802	1984	3500.47	2160.81	1914.06
6	600	FLLSPR	0.66369	0.563731	1984	3500.47	2323.23	1973.32
7	700	FLLSPR	0.76522	0.585189	1984	3500.47	2678.64	2048.43
8	800	FLLSPR	0.90545	0.646234	1984	3500.47	3169.50	2262.12
9	900	FLLSPR	0.97535	0.701185	1984	3500.47	3414.19	2454.47
10	1000	FLLSPR	0.99137	0.739467	1984	3500.47	3470.25	2588.48
11	1100	FLLSPR	1.00000	0.775057	1984	3500.47	3500.47	2713.06
12	1200	FLLSPR	0.98409	0.784353	1984	3500.47	3444.78	2745.60
13	1300	FLLSPR	0.95576	0.755167	1984	3500.47	3345.61	2643.43
14	1400	FLLSPR	0.96552	0.713552	1984	3500.47	3379.78	2497.76
15	1500	FLLSPR	0.94795	0.694084	1984	3500.47	3318.27	2429.62
16	1600	FLLSPR	0.89632	0.683944	1984	3500.47	3137.54	2394.12
17	1700	FLLSPR	0.93936	0.707229	1984	3500.47	3288.19	2475.63
18	1800	FLLSPR	0.92212	0.720038	1984	3500.47	3227.86	2520.47
19	1900	FLLSPR	0.91322	0.732920	1984	3500.47	3196.70	2565.56
20	2000	FLLSPR	0.93103	0.746455	1984	3500.47	3259.03	2612.94
21	2100	FLLSPR	0.88355	0.763671	1984	3500.47	3092.83	2673.20
22	2200	FLLSPR	0.86087	0.726714	1984	3500.47	3013.43	2543.84
23	2300	FLLSPR	0.80692	0.666139	1984	3500.47	2824.59	2331.80
24	2400	FLLSPR	0.71751	0.619738	1984	3500.47	2511.63	2169.37

"STATE ESTIMATION PROGRAM"

TABLE 6

```
DATA NEW;
  INFILE ULLOIN;
  INPUT HOUR SEASON $ YEAR WDGR WDCOM WDIND WDOTH WDPPL;
PROC PRINT DATA=NEW;
  TITLE DATA NEW;

PROC NLIN DATA=NEW BEST=3;
  PARMS A1=.5 TO 1 BY .1
        A2=.5 TO 1 BY .1
        A3=.5 TO 1 BY .1
        A4=.5 TO 1 BY .1;
  MODEL WDPPL=(A1*WDGR) + (A2*WDCOM) + (A3*WDIND) + (A4*WDOTH);
  DER.A1=WDGR;
  DER.A2=WDCOM;
  DER.A3=WDIND;
  DER.A4=WDOTH;
  OUTPUT OUT=NEW1
           P=PPL
           R=RES
       PARMS=A1 A2 A3 A4 SSE=SS;

PROC PRINT DATA=NEW1;
  TITLE DATA NEW1;

PROC PLOT DATA=NEW1;
  TITLE PROC PLOT REPORT: 1=WDGR 2=WDCOM 3=WDIND 4=WDOTH 5=WDPPL;
  PLOT WDGR*HOUR='1' WDCOM*HOUR='2' WDIND*HOUR='3' WDOTH*HOUR='4'
  WDPPL*HOUR='5'/OVERLAY;
```

Case 1

This case analyzed the data for 1984, Fall-Spring over a 24 hour period for each of the load groups. The load factor was iterated by 0.1 ($\propto$) from 0.5 to 1.0. After two (2) iterations:

——1	——2	——3	——4	Residual SS
1.23	0.77	1.38	1.08	31335

The actual results can be seen in Tables 7 to 11 and Figures 5-9. A second computer run was made varying $\propto$ from 0.5 to 1.0 and iterating by 0.05 to achieve greater accuracy. Tables 12 to 16 and Figure 10 show the results. They were essentially unchanged, indicating the initial data points used were very close to the estimated values.

"STATE ESTIMATION DATA SET"

TABLE 7

DATA NEW

OBS	HOUR	SEASON	YEAR	WDGR	WDCOM	WDIND	WDOTH	WDPPL
1	100	FLLSPR	1984	376.557	553.53	934.06	104.394	2250.03
2	200	FLLSPR	1984	347.518	544.10	909.16	96.672	2189.76
3	300	FLLSPR	1984	328.579	531.50	899.37	90.239	2140.79
4	400	FLLSPR	1984	322.211	526.24	871.14	93.350	2118.67
5	500	FLLSPR	1984	335.471	537.15	888.21	94.967	2160.81
6	600	FLLSPR	1984	394.066	570.31	919.70	99.983	2323.23
7	700	FLLSPR	1984	519.492	638.19	987.87	113.020	2678.84
8	800	FLLSPR	1984	599.218	841.18	1151.21	137.187	3159.60
9	900	FLLSPR	1984	581.869	1004.06	1240.01	154.388	3414.19
10	1000	FLLSPR	1984	550.146	1058.38	1275.46	160.841	3470.25
11	1100	FLLSPR	1984	559.094	1096.22	1296.82	163.902	3500.47
12	1200	FLLSPR	1984	569.721	1069.64	1285.36	158.235	3444.78
13	1300	FLLSPR	1984	531.288	1032.15	1265.50	147.682	3345.61
14	1400	FLLSPR	1984	505.191	1081.42	1312.35	150.167	3379.78
15	1500	FLLSPR	1984	489.724	1046.95	1255.08	142.798	3318.27
16	1600	FLLSPR	1984	541.035	956.64	1213.83	131.938	3137.54
17	1700	FLLSPR	1984	655.969	891.66	1178.44	134.328	3288.19
18	1800	FLLSPR	1984	768.189	795.94	1128.79	139.944	3227.86
19	1900	FLLSPR	1984	748.295	767.59	1115.73	145.279	3196.70
20	2000	FLLSPR	1984	726.037	811.55	1103.12	156.010	3259.03
21	2100	FLLSPR	1984	706.077	783.04	1088.40	166.631	3092.83
22	2200	FLLSPR	1984	683.812	721.70	1061.12	152.394	3013.43
23	2300	FLLSPR	1984	619.302	670.64	1013.45	128.908	2824.59
24	2400	FLLSPR	1984	466.712	607.81	963.58	123.812	2511.63

TABLE 8

DATA NEW

NON-LINEAR LEAST SQUARES GRID SEARCH   DEPENDENT VARIABLE WDPPL

A1	A2	A3	A4	RESIDUAL SS
1.0	1.0	1.0	1.0	3322650.31502600
1.0	1.0	1.0	0.9	3565680.11852389
1.0	1.0	1.0	0.8	3817459.65448916

TABLE 9

DATA NEW

NON-LINEAR LEAST SQUARES ITERATIVE PHASE

DEPENDENT VARIABLE: WDPPL   METHOD: GAUSS-NEWTON

ITERATION	A1	A2	A3	A4	RESIDUAL
0	1.00000000	1.00000000	1.00000000	1.00000000	3322650.3150266
1	1.23265924	0.76946298	1.37829993	1.08325109	31335.7583331
2	1.23265924	0.76946298	1.37829993	1.08325109	31335.7583331

NOTE: CONVERGENCE CRITERION MET.

TABLE 10

NON-LINEAR LEAST SQUARES SUMMARY STATISTICS   DEPENDENT VARIABLE WDPPL

SOURCE	DF	SUM OF SQUARES	MEAN SQUARE
REGRESSION	4	212418458.72606677	53104614.68151669
RESIDUAL	20	31335.75833318	1566.78791666
UNCORRECTED TOTAL	24	212449794.48439995	
(CORRECTED TOTAL)	23	5668006.91213346	

PARAMETER	ESTIMATE	ASYMPTOTIC STD. ERROR	ASYMPTOTIC 95 % CONFIDENCE INTERVAL LOWER	UPPER
A1	1.23265924	0.11252854	0.99793060	1.46738789
A2	0.76946298	0.09382108	0.57375710	0.96516885
A3	1.37829993	0.09076887	1.18896081	1.56763906
A4	1.08325109	0.97382684	-0.94810081	3.11460298

ASYMPTOTIC CORRELATION MATRIX OF THE PARAMETERS

	A1	A2	A3	A4
A1	1.000000	0.422494	0.074200	-0.771565
A2	0.422494	1.000000	-0.480485	-0.413796
A3	0.074200	-0.480485	1.000000	-0.516845
A4	-0.771565	-0.413796	-0.516845	1.000000

"LEASE SQUARES SUMMARY"

TABLE 11

DATA NEW1

OBS	HOUR	SEASON	YEAR	WDGR	WDCOM	WDIND	WDOTH	WDFPL	FPL	RES	A1	A2	A3	A4	SS
1	100	FLLSPR	1984	376.557	553.53	934.06	104.394	2250.03	2290.59	-40.557	1.23266	0.769463	1.3783	1.08325	31335.8
2	200	FLLSPR	1984	347.518	544.10	909.16	96.672	2189.76	2204.85	-15.091	1.23266	0.769463	1.3783	1.08325	31335.8
3	300	FLLSPR	1984	328.579	531.50	899.37	90.239	2140.79	2151.35	-10.559	1.23266	0.769463	1.3783	1.08325	31335.8
4	400	FLLSPR	1984	322.211	526.24	871.14	93.350	2118.67	2103.91	14.758	1.23266	0.769463	1.3783	1.08325	31335.8
5	500	FLLSPR	1984	335.471	537.15	888.21	94.967	2160.81	2153.93	6.879	1.23266	0.769463	1.3783	1.08325	31335.8
6	600	FLLSPR	1984	394.066	570.31	919.70	99.983	2323.23	2300.51	22.719	1.23266	0.769463	1.3783	1.08325	31335.8
7	700	FLLSPR	1984	519.492	638.19	987.87	113.020	2678.84	2615.43	63.410	1.23266	0.769463	1.3783	1.08325	31335.8
8	800	FLLSPR	1984	599.218	841.18	1151.21	137.187	3159.60	3121.21	38.391	1.23266	0.769463	1.3783	1.08325	31335.8
9	900	FLLSPR	1984	581.869	1004.06	1240.01	154.388	3414.19	3366.18	48.010	1.23266	0.769463	1.3783	1.08325	31335.8
10	1000	FLLSPR	1984	550.146	1058.38	1275.46	160.841	3470.25	3424.72	45.526	1.23266	0.769463	1.3783	1.08325	31335.8
11	1100	FLLSPR	1984	559.094	1096.22	1296.82	163.902	3500.47	3497.63	2.843	1.23266	0.769463	1.3783	1.08325	31335.8
12	1200	FLLSPR	1984	569.721	1069.64	1285.36	158.235	3444.78	3468.34	-23.560	1.23266	0.769463	1.3783	1.08325	31335.8
13	1300	FLLSPR	1984	531.288	1032.15	1265.50	147.682	3345.61	3353.31	-7.704	1.23266	0.769463	1.3783	1.08325	31335.8
14	1400	FLLSPR	1984	505.191	1081.42	1312.35	150.167	3379.78	3426.32	-46.541	1.23266	0.769463	1.3783	1.08325	31335.8
15	1500	FLLSPR	1984	489.724	1046.95	1255.08	142.798	3318.27	3293.81	24.455	1.23266	0.769463	1.3783	1.08325	31335.8
16	1600	FLLSPR	1984	541.035	956.64	1213.83	131.938	3137.54	3218.95	-81.415	1.23266	0.769463	1.3783	1.08325	31335.8
17	1700	FLLSPR	1984	655.969	891.66	1178.44	134.328	3288.19	3264.44	23.750	1.23266	0.769463	1.3783	1.08325	31335.8
18	1800	FLLSPR	1984	768.189	795.94	1128.79	139.944	3227.86	3266.77	-38.907	1.23266	0.769463	1.3783	1.08325	31335.8
19	1900	FLLSPR	1984	748.295	767.59	1115.73	145.279	3196.70	3208.21	-11.509	1.23266	0.769463	1.3783	1.08325	31335.8
20	2000	FLLSPR	1984	726.037	811.55	1103.12	156.010	3259.03	3208.84	50.188	1.23266	0.769463	1.3783	1.08325	31335.8
21	2100	FLLSPR	1984	706.077	783.04	1088.40	166.631	3092.83	3153.52	-60.687	1.23266	0.769463	1.3783	1.08325	31335.8
22	2200	FLLSPR	1984	683.812	721.70	1061.12	152.394	3013.43	3025.85	-12.421	1.23266	0.769463	1.3783	1.08325	31335.8
23	2300	FLLSPR	1984	619.302	670.64	1013.45	128.908	2824.59	2815.90	8.691	1.23266	0.769463	1.3783	1.08325	31335.8
24	2400	FLLSPR	1984	466.712	607.81	963.58	123.812	2511.63	2505.21	6.424	1.23266	0.769463	1.3783	1.08325	31335.8

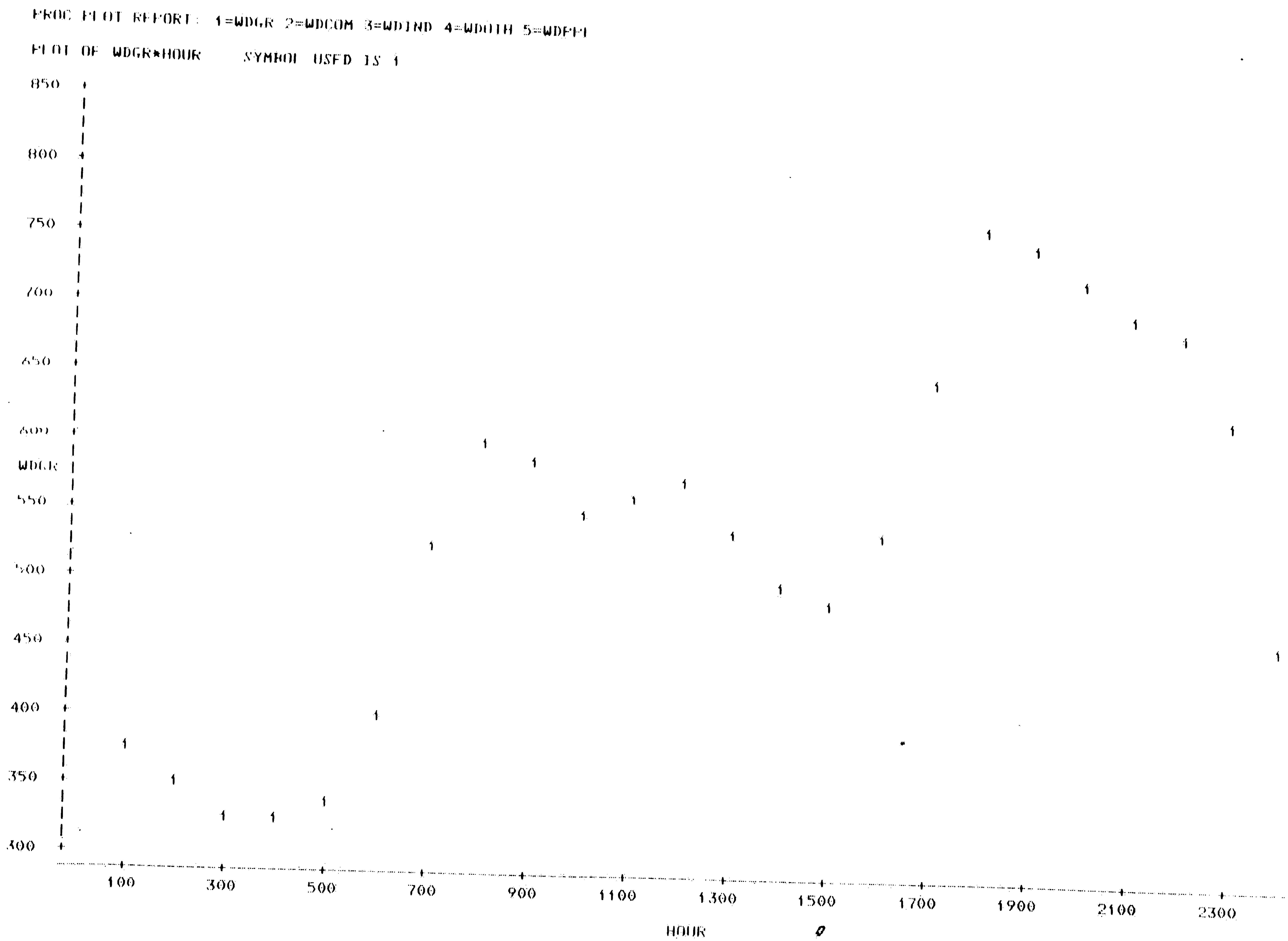

PROC PLOT REPORT: 1=WDGR 2=WDCOM 3=WDIND 4=WDOTH
PLOT OF WDGR*HOUR SYMBOL USED IS 1
WDGR
850
800
750
700
650
600
550
500
450
400
350
300
100
300
500
700
900
1100
1300
1500
1700
1900
2100
2300
HOUR

FIGURE 5

PROC PLOT REPORT: 1=WDGR 2=WDCOM 3=WDIND 4=WDOTH 5=WDFED

PLOT OF WDCOM*HOUR   SYMBOL USED IS 2

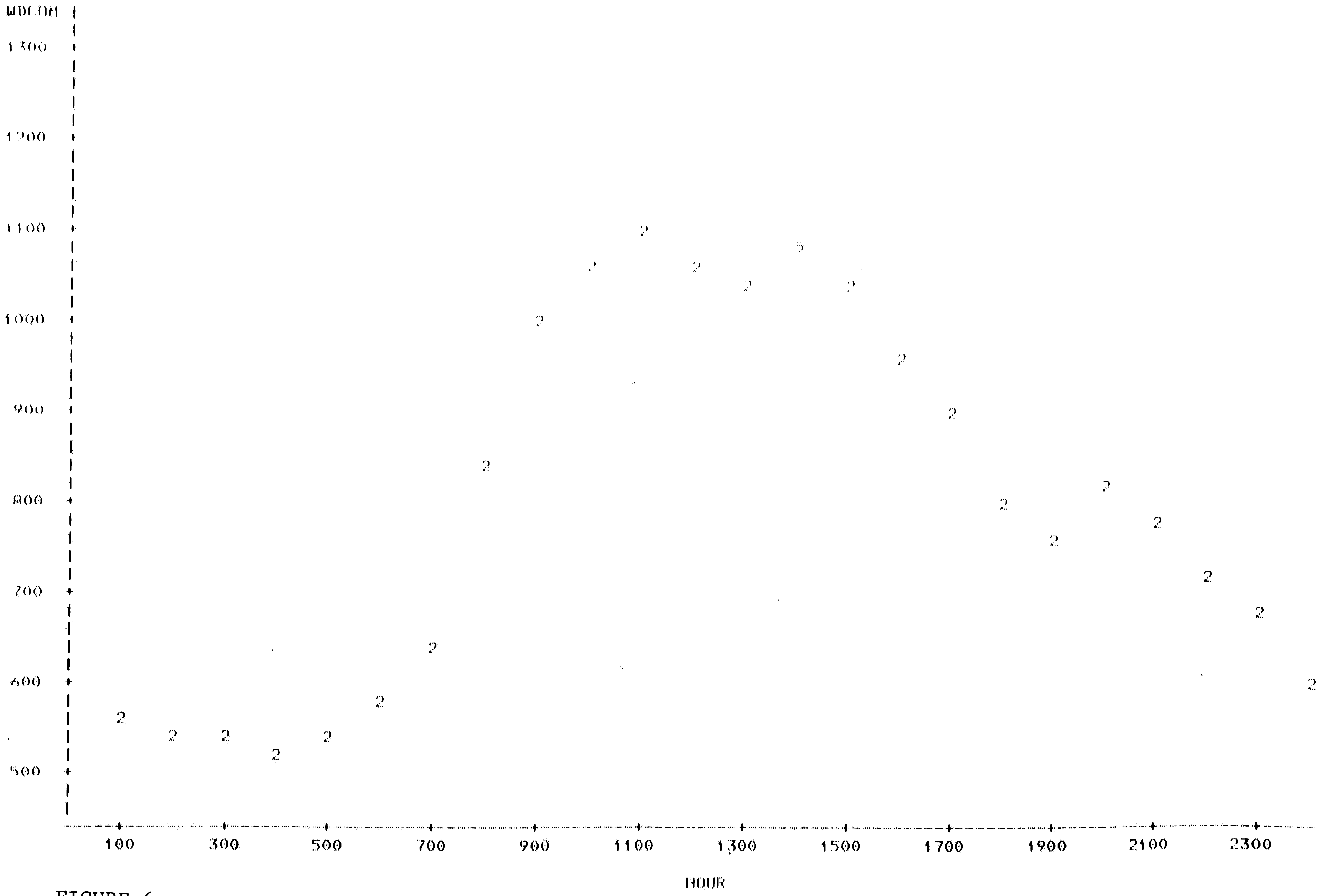


FIGURE 6

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PAGE(S) 58-60

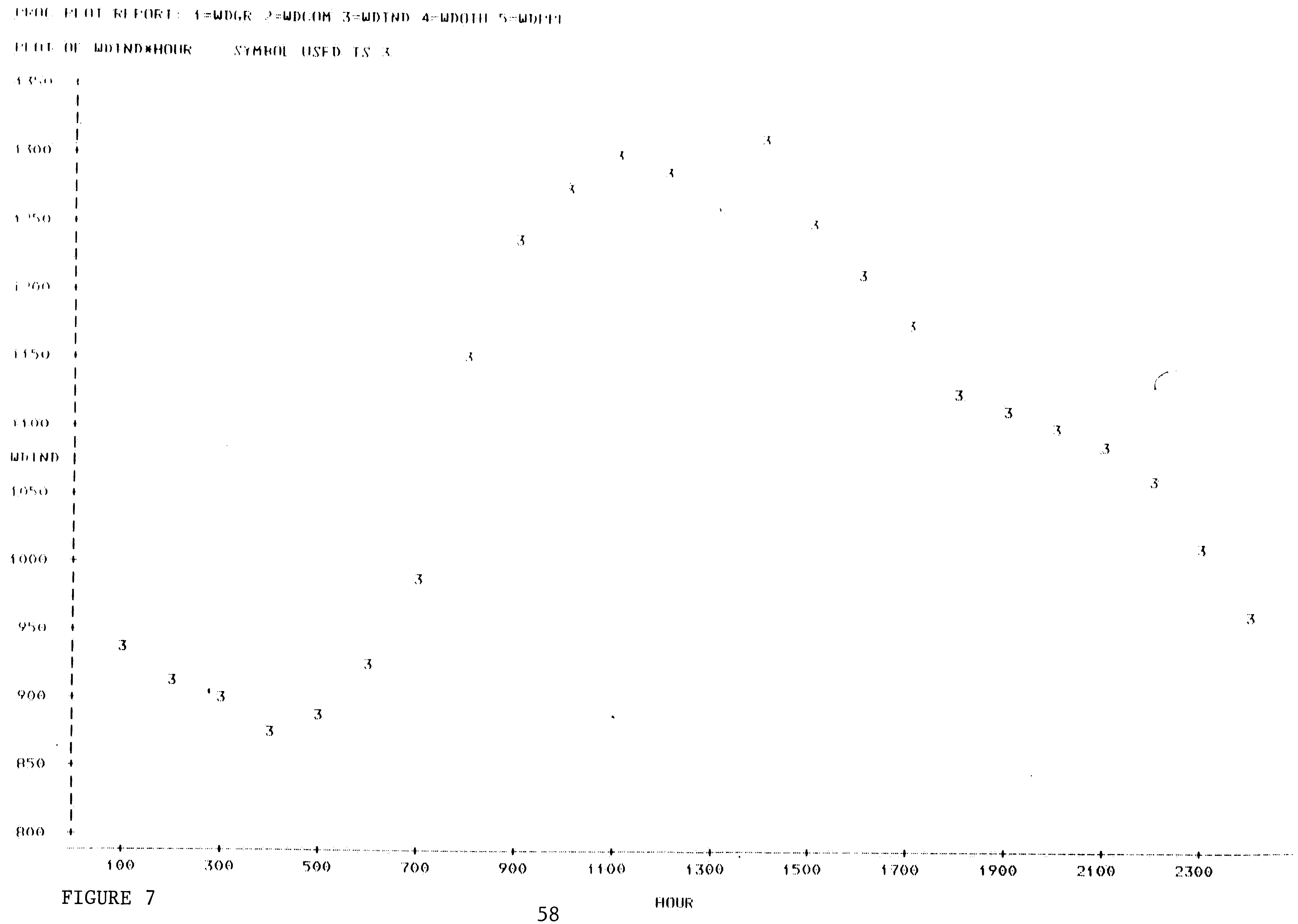

PROC PLOT REPORT: 1=WDGR 2=WDCOM 3=WDIND 4=WDOTH 5=WDPPI
PLOT OF WDIND*HOUR SYMBOL USED IS 3
1300
1150
1100
WDIND
1050
1000
950
900
850
800
100
300
500
700
900
1100
1300
1500
1700
1900
2100
2300
HOUR

FIGURE 7

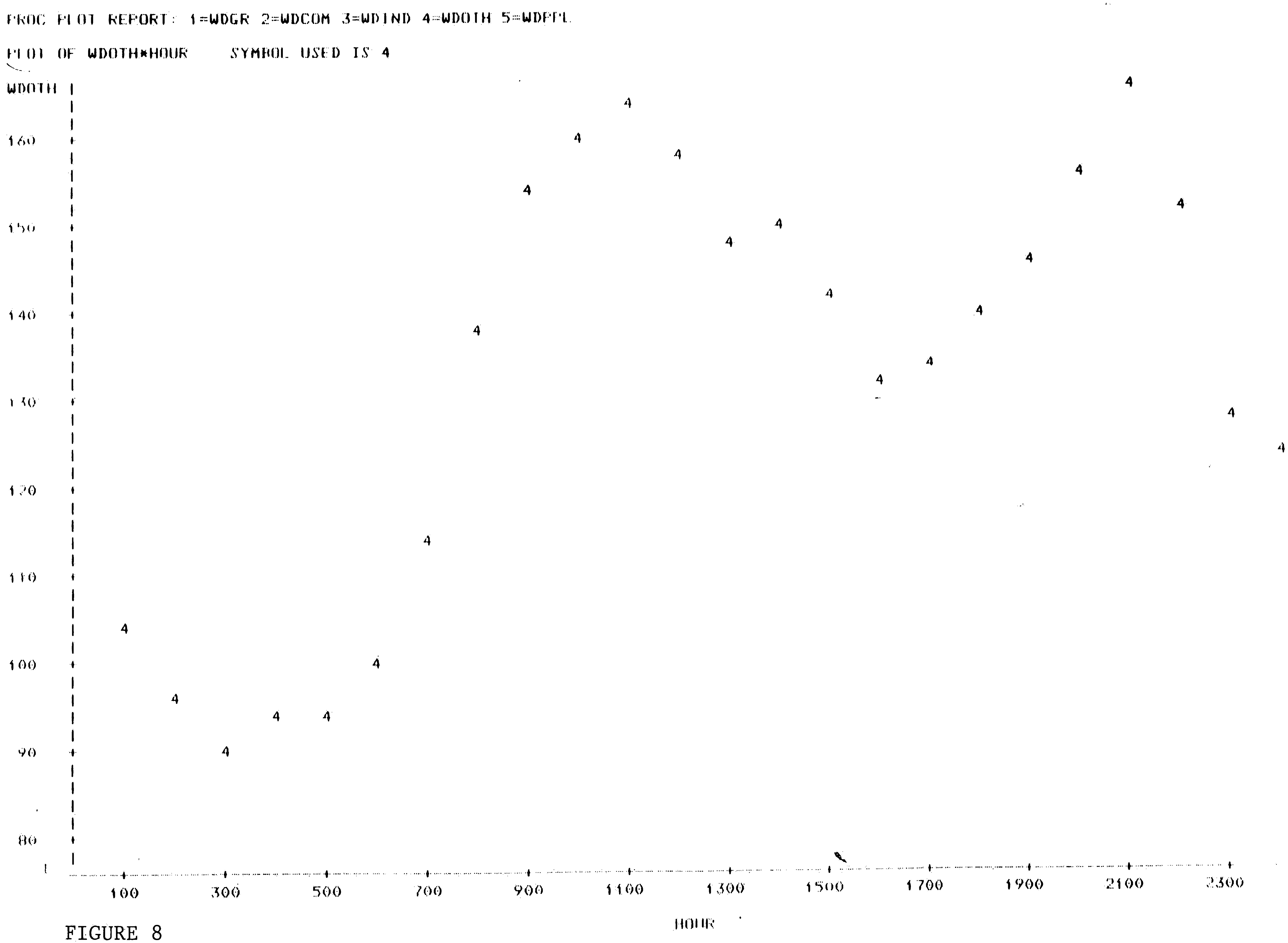

PROC PLOT REPORT: 1=WDGR 2=WDCOM 3=WDIND 4=WDOTH 5=WDPPL
PLOT OF WDOTH*HOUR   SYMBOL USED IS 4
WDOTH
160
150
140
130
120
110
100
90
80
100
300
500
700
900
1100
1300
1500
1700
1900
2100
2300
HOUR

FIGURE 8

PROC PLOT REPORT: 1=WDGR 2=WDCOM 3=WDIND 4=WDOTH 5=WDPEL

PLOT OF WDPEL*HOUR   SYMBOL USED IS 5

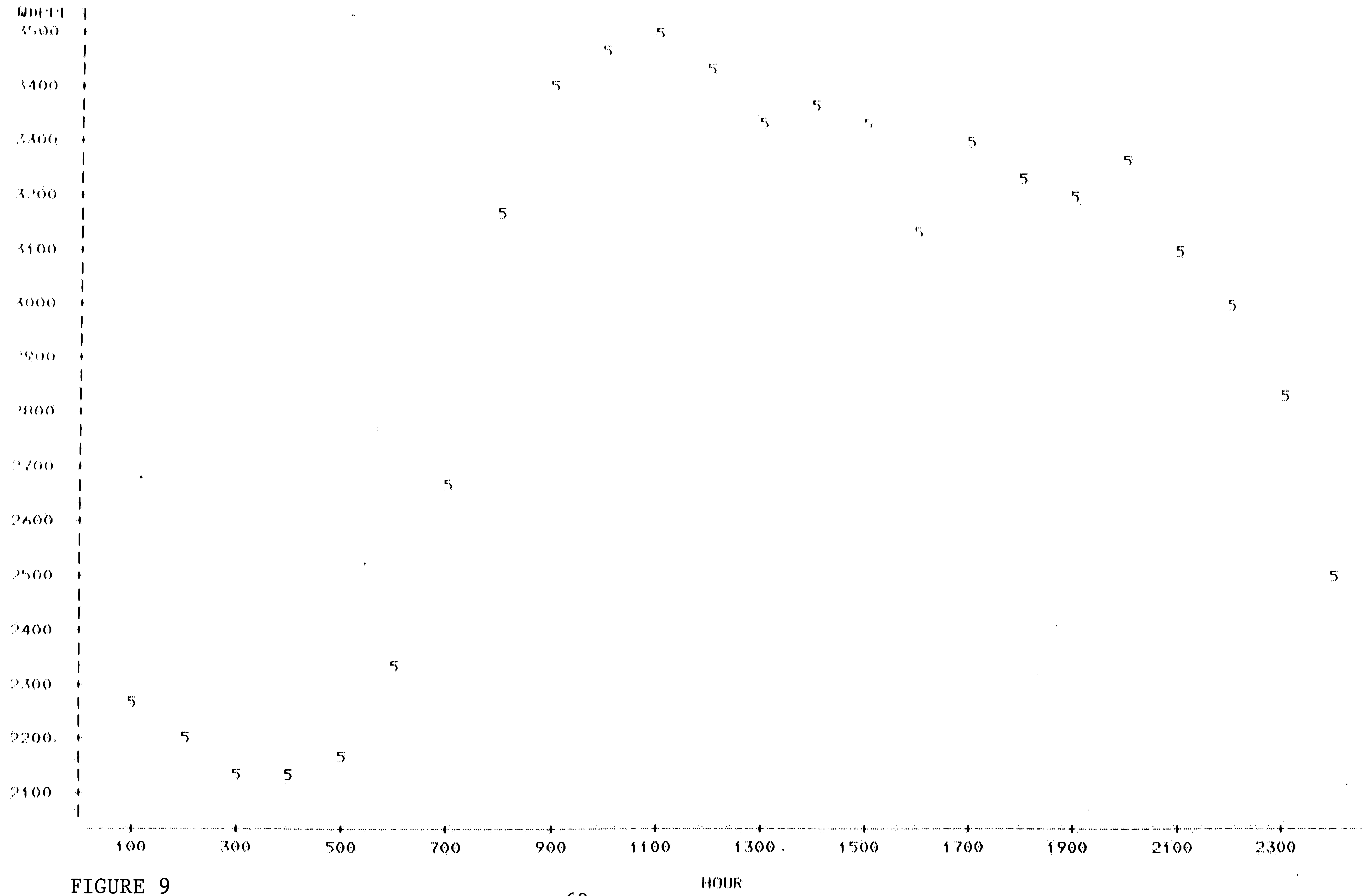


FIGURE 9

"STATE ESTIMATION DATA SET"

TABLE 12

DATA NEW

OBS	HOUR	SEASON	YEAR	WDGR	WDCOM	WDIND	WDOTH	WDPPL
1	100	FLLSPR	1984	376.557	553.53	934.06	104.394	2250.03
2	200	FLLSPR	1984	347.518	544.10	909.16	96.672	2189.76
3	300	FLLSPR	1984	328.579	531.50	899.37	90.239	2140.79
4	400	FLLSPR	1984	322.211	526.24	871.14	93.350	2118.67
5	500	FLLSPR	1984	335.471	537.15	888.21	94.967	2160.81
6	600	FLLSPR	1984	394.066	570.31	919.70	99.983	2323.23
7	700	FLLSPR	1984	519.492	638.19	987.87	113.020	2678.84
8	800	FLLSPR	1984	599.218	841.18	1151.21	137.187	3159.60
9	900	FLLSPR	1984	581.869	1004.06	1240.01	154.388	3414.19
10	1000	FLLSPR	1984	550.146	1058.38	1275.46	160.841	3470.25
11	1100	FLLSPR	1984	559.094	1096.22	1296.82	163.902	3500.47
12	1200	FLLSPR	1984	569.721	1069.64	1285.36	158.235	3444.78
13	1300	FLLSPR	1984	531.288	1032.15	1265.50	147.682	3345.61
14	1400	FLLSPR	1984	505.191	1081.42	1312.35	150.167	3379.78
15	1500	FLLSPR	1984	489.724	1046.95	1255.08	142.798	3318.27
16	1600	FLLSPR	1984	541.035	956.64	1213.83	131.938	3137.54
17	1700	FLLSPR	1984	655.969	891.66	1178.44	134.328	3288.19
18	1800	FLLSPR	1984	768.189	795.94	1128.79	139.944	3227.86
19	1900	FLLSPR	1984	748.295	767.59	1115.73	145.279	3196.70
20	2000	FLLSPR	1984	726.037	811.55	1103.12	156.010	3259.03
21	2100	FLLSPR	1984	706.077	783.04	1088.40	166.631	3092.83
22	2200	FLLSPR	1984	683.812	721.70	1061.12	152.394	3013.43
23	2300	FLLSPR	1984	619.302	670.64	1013.45	128.908	2824.59
24	2400	FLLSPR	1984	466.712	607.81	963.58	123.812	2511.63

TABLE 13

DATA NEW

NON-LINEAR LEAST SQUARES GRID SEARCH   DEPENDENT VARIABLE WDPPL

A1	A2	A3	A4	RESIDUAL SS
1.00	1.00	1.00	1.00	3322650.31502600
1.00	1.00	1.00	0.95	3443071.50021652
1.00	1.00	1.00	0.90	3565680.11852389

TABLE 14

DATA NEW

NON-LINEAR LEAST SQUARES ITERATIVE PHASE

DEPENDENT VARIABLE: WDPPL METHOD: GAUSS-NEWTON

ITERATION	A1	A2	A3	A4	RESIDUAL SS
0	1.00000000	1.00000000	1.00000000	1.00000000	3322650.31502600
1	1.23265924	0.76946298	1.37829993	1.08325109	31335.75833318
2	1.23265924	0.76946298	1.37829993	1.08325109	31335.75833318

NOTE: CONVERGENCE CRITERION MET.

TABLE 15

DATA NEW

NON-LINEAR LEAST SQUARES SUMMARY STATISTICS   DEPENDENT VARIABLE WDPPL

SOURCE	DF	SUM OF SQUARES	MEAN SQUARE
REGRESSION	4	212418458.72606677	53104614.68151669
RESIDUAL	20	31335.75833318	1566.78791666
UNCORRECTED TOTAL	24	212449794.48439995	
(CORRECTED TOTAL)	23	5668006.91213346	

PARAMETER	ESTIMATE	ASYMPTOTIC STD. ERROR	ASYMPTOTIC 95 % CONFIDENCE INTERVAL LOWER	UPPER
A1	1.23265924	0.11252854	0.99793060	1.46738789
A2	0.76946298	0.09382108	0.57375710	0.96516885
A3	1.37829993	0.09076887	1.18896081	1.56763906
A4	1.08325109	0.97382684	-0.94810081	3.11460298

ASYMPTOTIC CORRELATION MATRIX OF THE PARAMETERS

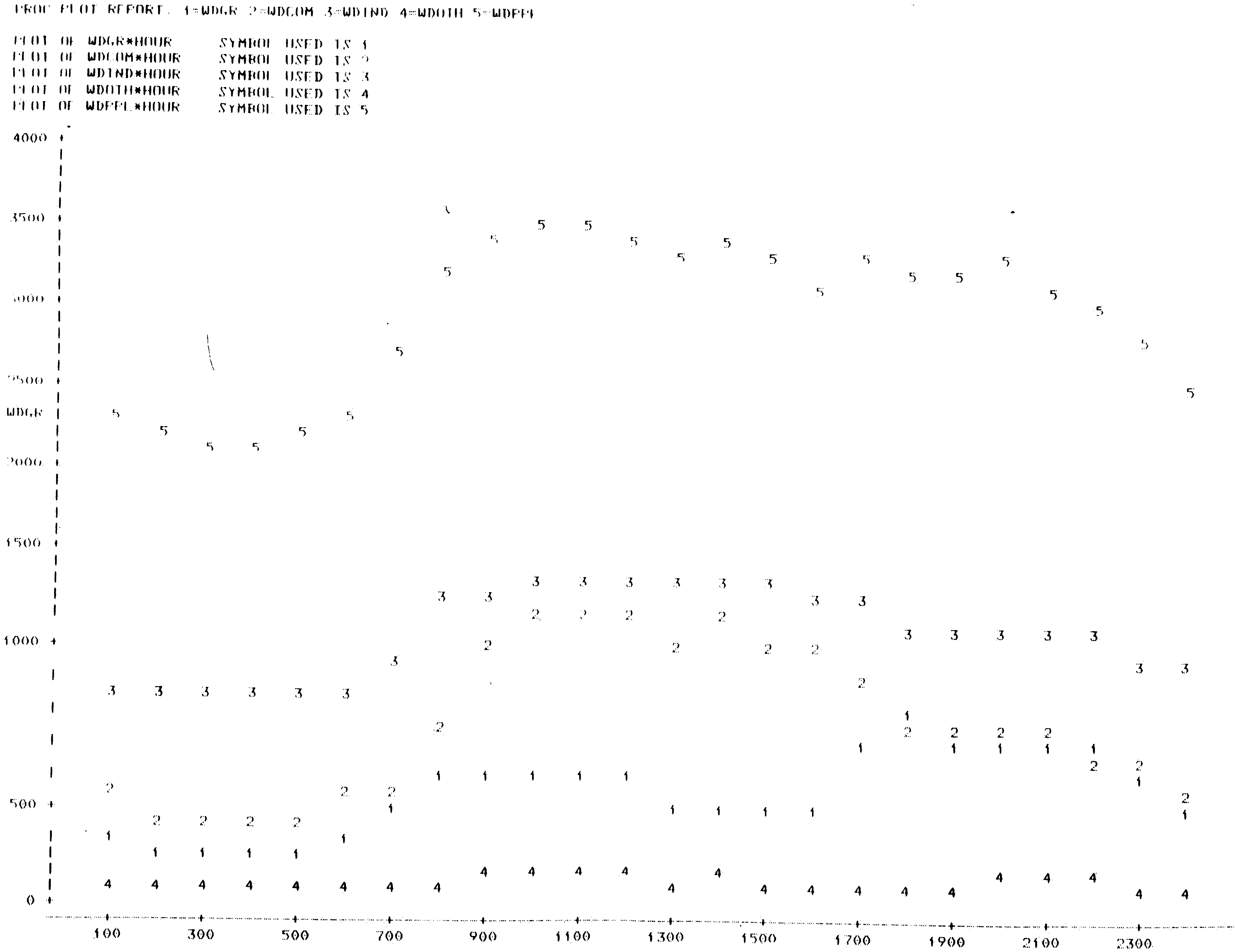
	A1	A2	A3	A4
A1	1.000000	0.422494	0.074200	-0.771565
A2	0.422494	1.000000	-0.480485	-0.413796
A3	0.074200	-0.480485	1.000000	-0.516845
A4	-0.771565	-0.413796	-0.516845	1.000000

"LEASE SQUARES SUMMARY"

TABLE 16

DATA NEW1

OBS	HOUR	SEASON	YEAR	WDGR	WDCOM	WDIND	WDOTH	WDPPI	PPI	RES	A1	A2	A3	A4	SS
1	100	FLLSPR	1984	376.557	553.53	934.06	104.394	2250.03	2290.59	-40.557	1.23266	0.769463	1.3783	1.08325	31335.8
2	200	FLLSPR	1984	347.518	544.10	909.16	96.672	2189.76	2204.85	-15.091	1.23266	0.769463	1.3783	1.08325	31335.8
3	300	FLLSPR	1984	328.579	531.50	899.37	90.239	2140.79	2151.35	-10.559	1.23266	0.769463	1.3783	1.08325	31335.8
4	400	FLLSPR	1984	322.211	526.24	871.14	93.350	2118.67	2103.91	14.758	1.23266	0.769463	1.3783	1.08325	31335.8
5	500	FLLSPR	1984	335.471	537.15	888.21	94.967	2160.81	2153.93	6.879	1.23266	0.769463	1.3783	1.08325	31335.8
6	600	FLLSPR	1984	394.066	570.31	919.70	99.983	2323.23	2300.51	22.719	1.23266	0.769463	1.3783	1.08325	31335.8
7	700	FLLSPR	1984	519.492	638.19	987.87	113.020	2678.84	2615.43	63.410	1.23266	0.769463	1.3783	1.08325	31335.8
8	800	FLLSPR	1984	599.218	841.18	1151.21	137.187	3159.60	3121.21	38.391	1.23266	0.769463	1.3783	1.08325	31335.8
9	900	FLLSPR	1984	581.869	1004.06	1240.01	154.388	3414.19	3366.18	48.010	1.23266	0.769463	1.3783	1.08325	31335.8
10	1000	FLLSPR	1984	550.146	1058.38	1275.46	160.841	3470.25	3424.72	45.526	1.23266	0.769463	1.3783	1.08325	31335.8
11	1100	FLLSPR	1984	559.094	1096.22	1296.82	163.902	3500.47	3497.63	2.843	1.23266	0.769463	1.3783	1.08325	31335.8
12	1200	FLLSPR	1984	569.721	1069.64	1285.36	158.235	3444.78	3468.34	-23.560	1.23266	0.769463	1.3783	1.08325	31335.8
13	1300	FLLSPR	1984	531.288	1032.15	1265.50	147.682	3345.61	3353.31	-7.704	1.23266	0.769463	1.3783	1.08325	31335.8
14	1400	FLLSPR	1984	505.191	1081.42	1312.35	150.167	3379.78	3426.32	-46.541	1.23266	0.769463	1.3783	1.08325	31335.8
15	1500	FLLSPR	1984	489.724	1046.95	1255.08	142.798	3318.27	3293.81	24.455	1.23266	0.769463	1.3783	1.08325	31335.8
16	1600	FLLSPR	1984	541.035	956.64	1213.83	131.938	3137.54	3218.95	-81.415	1.23266	0.769463	1.3783	1.08325	31335.8
17	1700	FLLSPR	1984	655.969	891.66	1178.44	134.328	3288.19	3264.44	23.750	1.23266	0.769463	1.3783	1.08325	31335.8
18	1800	FLLSPR	1984	768.189	795.94	1128.79	139.944	3227.86	3266.77	-38.907	1.23266	0.769463	1.3783	1.08325	31335.8
19	1900	FLLSPR	1984	748.295	767.59	1115.73	145.279	3196.70	3208.21	-11.509	1.23266	0.769463	1.3783	1.08325	31335.8
20	2000	FLLSPR	1984	726.037	811.55	1103.12	156.010	3259.03	3208.84	50.188	1.23266	0.769463	1.3783	1.08325	31335.8
21	2100	FLLSPR	1984	706.077	783.04	1088.40	166.631	3092.83	3153.52	-60.687	1.23266	0.769463	1.3783	1.08325	31335.8
22	2200	FLLSPR	1984	683.812	721.70	1061.12	152.394	3013.43	3025.85	-12.421	1.23266	0.769463	1.3783	1.08325	31335.8
23	2300	FLLSPR	1984	619.302	670.64	1013.45	128.908	2824.59	2815.90	8.691	1.23266	0.769463	1.3783	1.08325	31335.8
24	2400	FLLSPR	1984	466.712	607.81	963.58	123.812	2511.63	2505.21	6.424	1.23266	0.769463	1.3783	1.08325	31335.8



PROC PLOT REPORT. 1=WDGR 2=WDCOM 3=WDIND 4=WDOTH 5=WDPPL
PLOT OF WDGR*HOUR SYMBOL USED IS 1
PLOT OF WDCOM*HOUR SYMBOL USED IS 2
PLOT OF WDIND*HOUR SYMBOL USED IS 3
PLOT OF WDOTH*HOUR SYMBOL USED IS 4
PLOT OF WDPPL*HOUR SYMBOL USED IS 5
4000
3500
3000
2500
WDGR
2000
1500
1000
500
0
100
300
500
700
900
1100
1300
1500
1700
1900
2100
2300

FIGURE 10

Conclusions

The results showed that the general residential group is time varying with peaks at 800 and 1800 hours. This probably correlates to the 800-1700 work day for most individuals. The largest peak was about 800 MW-hours.

The commercial and industrial curves were similar in that a peak occurs about 800 hours and remains fairly constant through about 1700 hours. Peak loads are 1100 and 1300 MW respectively.

The "other" load group is levelized throughout the day at about 200 MW. Overall, the total load curve is time varying with a peak at 900 hours and 2000 hours and then dropping off during the late evening.

Satisfied that a good estimate of the load curves was performed, the next case study examined the effects or sensitivity of the curves by varying the load factor (α). This would illustrate the impact on the total load curve and the potential for benefit of shifting a given load group.

Case 2

Alpha (α) was varied for each load group and in combinations. The results can be seen in Tables 17 to 23 and Figures 11 to 15. The results of this data lead to the conclusions that:

1. The "other" load curve has little effect on the total load and is probably of little value in a marketing strategy.

2. The residential, commercial, and industrial loads either individually or in combinations have a significant effect on the shape of the total load curve. It is probably feasible to obtain any desired total load shape depending on the utilities objectives and the motivation provided to the user.

There are obviously many factors that affect the shape of the total load curve. Of particular interest in the next case study is the affect of the various tariffs applicable to each load group. First, the optimal mix will be examined. This mix maximizes the utility's revenues but may not meet the objectives of a total load curve. Of additional interest is a sensitivity analysis of the price coefficients and the potential it offers for modifying the total curve and meeting the revenue requirements of the utility.

"ALPHA SENSITIVITY PROGRAM"

TABLE 17

```
 DATA NEW1;
INFILE ULLOIN;
INPUT HOUR SEASON $ YEAR WDGR WDCOM WDIND WDOTH WDPPL;
           A1=1.23265924;
           A2=.76946298;
           A3=1.37829993;
           A4=1.2;
   GR=WDGR*A1;
   COM=WDCOM*A2;
   IND=WDIND*A3;
   OTH=WDOTH*A4;
   PPL=GR+COM+IND+OTH;
   RES=PPL-WDPPL;
   OUTPUT;
 PROC PRINT DATA=NEW1;
   TITLE DATA NEW1;
 PROC PLOT DATA=NEW1;
   TITLE PROC PLOT REPORT: 1=GR   2=COM   3=IND   4=OTH   5=PPL  ;
   PLOT   GR*HOUR='1'   COM*HOUR='2'   IND*HOUR='3'   OTH*HOUR='4'
     PPL*HOUR='5'/OVERLAY;
```

"SENSITIVITY DATA SUMMARY"

TABLE 18

Data NEW1

OBS	HOUR	SEASON	YEAR	WDGR	WDCOM	WDIND	WDOTH	WDFFL	A1	A2
1	100	FLLSPR	1984	376.557	553.53	934.06	104.394	2250.03	1.4	0.769463
2	200	FLLSPR	1984	347.518	544.10	909.16	96.672	2189.76	1.4	0.769463
3	300	FLLSPR	1984	328.579	531.50	899.37	90.239	2140.79	1.4	0.769463
4	400	FLLSPR	1984	322.211	526.24	871.14	93.350	2118.67	1.4	0.769463
5	500	FLLSPR	1984	335.471	537.15	888.21	94.967	2160.81	1.4	0.769463
6	600	FLLSPR	1984	394.066	570.31	919.70	99.983	2323.23	1.4	0.769463
7	700	FLLSPR	1984	519.492	638.19	987.87	113.020	2678.84	1.4	0.769463
8	800	FLLSPR	1984	599.218	841.18	1151.21	137.187	3159.60	1.4	0.769463
9	900	FLLSPR	1984	581.869	1004.06	1240.01	154.388	3414.19	1.4	0.769463
10	1000	FLLSPR	1984	550.146	1058.38	1275.46	160.841	3470.25	1.4	0.769463
11	1100	FLLSPR	1984	559.094	1096.22	1296.82	163.902	3500.47	1.4	0.769463
12	1200	FLLSPR	1984	569.721	1069.64	1285.36	158.235	3444.78	1.4	0.769463
13	1300	FLLSPR	1984	531.288	1032.15	1265.50	147.682	3345.61	1.4	0.769463
14	1400	FLLSPR	1984	505.191	1081.42	1312.35	150.167	[illegible]	1.4	0.769463
15	1500	FLLSPR	1984	489.724	1046.95	1255.08	142.798	3318.27	1.4	0.769463
16	1600	FLLSPR	1984	541.035	956.64	1213.83	131.938	3137.54	1.4	0.769463
17	1700	FLLSPR	1984	655.969	891.66	1178.44	134.328	3288.19	1.4	0.769463
18	1800	FLLSPR	1984	768.189	795.94	1128.79	139.944	3227.86	1.4	0.769463
19	1900	FLLSPR	1984	748.295	767.59	1115.73	145.279	3196.70	1.4	0.769463
20	2000	FLLSPR	1984	726.037	811.55	1103.12	156.010	3259.03	1.4	0.769463
21	2100	FLLSPR	1984	706.077	783.04	1088.40	156.631	3092.83	1.4	0.769463
22	2200	FLLSPR	1984	683.812	721.70	1061.12	152.394	3013.43	1.4	0.769463
23	2300	FLLSPR	1984	619.302	670.64	1013.45	128.908	2874.59	1.4	0.769463
24	2400	FLLSPR	1984	466.712	607.81	963.58	123.812	2511.63	1.4	0.769463

OBS	A3	A4	GR	COM	IND	OTH	FFL	RES
1	1.3783	1.08325	527.18	425.921	1287.41	113.085	2353.30	103.570
2	1.3783	1.08325	486.53	418.665	1253.10	104.720	2263.01	73.245
3	1.3783	1.08325	460.01	408.970	1239.60	97.751	2206.33	65.543
4	1.3783	1.08325	451.10	404.922	1200.69	101.121	2157.83	39.161
5	1.3783	1.08325	469.66	413.317	1224.22	102.873	2210.07	49.259
6	1.3783	1.08325	551.69	438.832	1267.62	108.307	2366.45	43.224
7	1.3783	1.08325	727.29	491.064	1361.58	122.429	2702.36	23.523
8	1.3783	1.08325	838.91	647.257	1586.71	148.608	3221.48	61.883
9	1.3783	1.08325	814.62	772.587	1709.11	167.241	3463.55	49.360
10	1.3783	1.08325	770.20	814.384	1757.97	174.231	3516.79	46.536
11	1.3783	1.08325	782.73	843.501	1787.41	177.547	3591.19	90.716
12	1.3783	1.08325	797.61	823.048	1771.61	171.408	3563.68	118.898
13	1.3783	1.08325	743.80	794.201	1744.24	159.977	3442.22	96.610
14	1.3783	1.08325	707.27	832.113	1808.81	162.669	3510.86	131.081
15	1.3783	1.08325	685.61	805.589	1729.88	154.686	3375.77	57.496
16	1.3783	1.08325	757.45	736.099	1673.02	142.922	3309.49	171.952
17	1.3783	1.08325	918.36	686.099	1624.24	145.511	3374.21	86.021
18	1.3783	1.08325	1075.46	612.446	1555.81	151.594	3395.32	167.457
19	1.3783	1.08325	1047.61	590.632	1537.81	157.374	3333.43	136.729
20	1.3783	1.08325	1016.45	624.458	1520.43	168.998	3330.34	71.308
21	1.3783	1.08325	988.51	602.520	1500.14	180.503	3271.67	178.843
22	1.3783	1.08325	957.34	555.321	1462.54	165.081	3140.28	126.851
23	1.3783	1.08325	867.02	516.033	1396.84	139.640	2919.53	94.943
24	1.3783	1.08325	653.40	467.687	1328.10	134.119	2583.31	71.676

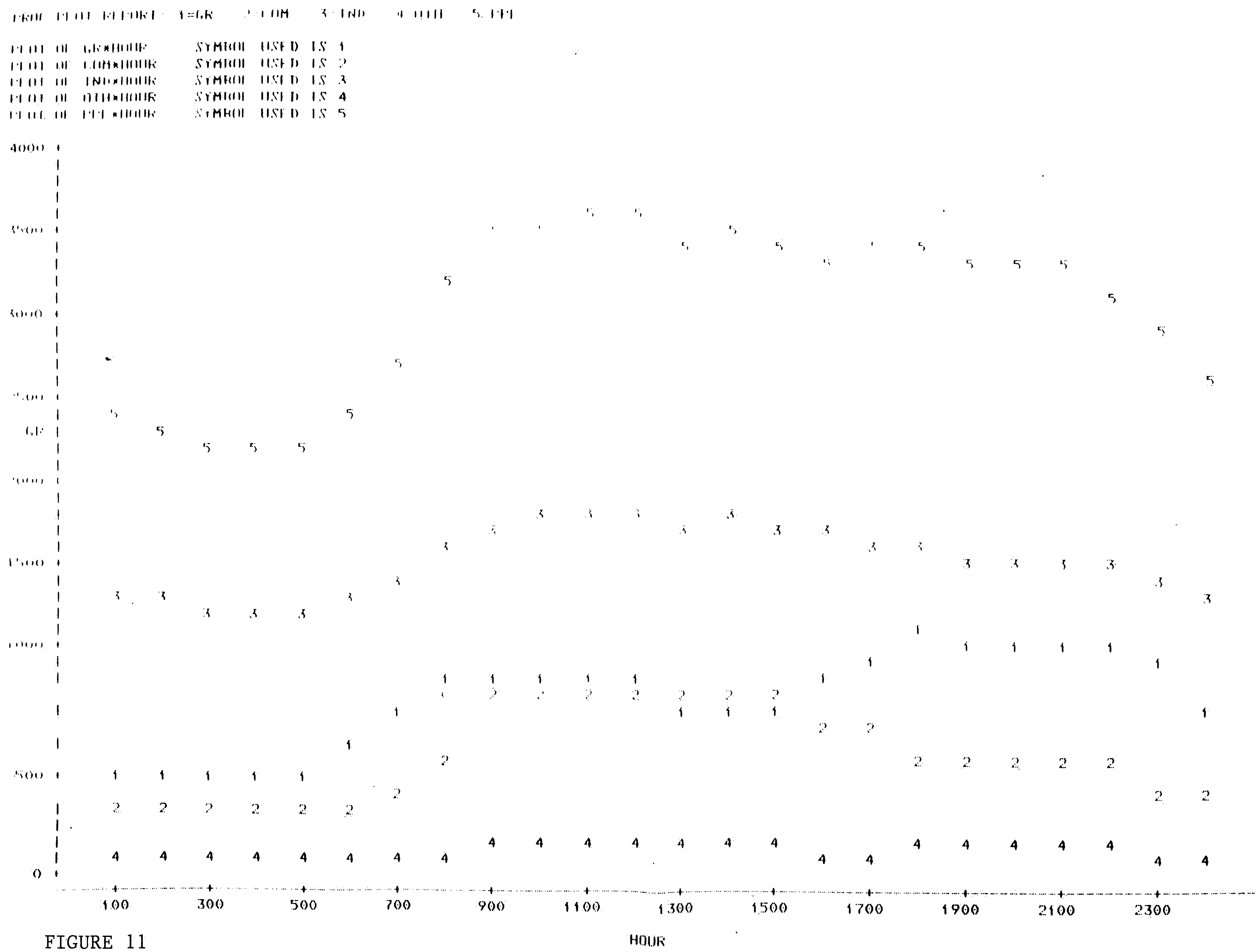

4000
3000
500
0
100
300
500
700
900
1100
1300
1500
1700
1900
2100
2300
HOUR

FIGURE 11

"SENSITIVITY DATA SUMMARY"

DATA NEW1

TABLE 19

OBS	HOUR	SEASON	YEAR	WDGR	WDCOM	WDIND	WDOTH	WDPPI	A1
1	100	FLLSPR	1984	376.557	553.53	934.06	104.394	2250.03	1.23266
2	200	FLLSPR	1984	347.518	544.10	909.16	96.672	2189.76	1.23266
3	300	FLLSPR	1984	328.579	531.50	899.37	90.239	2140.79	1.23266
4	400	FLLSPR	1984	322.211	526.24	871.14	93.350	2118.67	1.23266
5	500	FLLSPR	1984	335.471	537.15	888.21	94.967	2160.81	1.23266
6	600	FLLSPR	1984	394.066	570.31	919.70	99.983	2323.23	1.23266
7	700	FLLSPR	1984	519.492	638.19	987.87	113.020	[illegible]	1.23266
8	800	FLLSPR	1984	599.218	841.18	1151.21	137.187	3159.60	1.23266
9	900	FLLSPR	1984	581.869	1004.06	1240.01	154.388	3414.19	1.23266
10	1000	FLLSPR	1984	550.146	1058.38	1275.46	160.841	3470.25	1.23266
11	1100	FLLSPR	1984	559.094	1096.22	1296.82	163.902	3500.47	1.23266
12	1200	FLLSPR	1984	569.721	1069.64	1285.36	158.235	3444.78	1.23266
13	1300	FLLSPR	1984	531.288	1032.15	1265.50	147.682	3345.61	1.23266
14	1400	FLLSPR	1984	505.191	1081.42	1312.35	150.167	3379.78	1.23266
15	1500	FLLSPR	1984	489.724	1046.95	1255.08	142.798	3318.27	1.23266
16	1600	FLLSPR	1984	541.035	956.64	1213.83	131.938	3137.54	1.23266
17	1700	FLLSPR	1984	655.969	891.66	1178.44	134.328	3288.19	1.23266
18	1800	FLLSPR	1984	768.189	795.94	1128.79	139.944	3227.86	1.23266
19	1900	FLLSPR	1984	748.295	767.59	1115.73	145.279	3196.70	1.23266
20	2000	FLLSPR	1984	726.037	811.55	1103.12	156.010	3259.03	1.23266
21	2100	FLLSPR	1984	706.077	783.04	1088.40	166.631	3092.83	1.23266
22	2200	FLLSPR	1984	683.812	721.70	1061.12	152.394	3013.43	1.23266
23	2300	FLLSPR	1984	619.302	670.64	1013.45	128.908	2824.59	1.23266
24	2400	FLLSPR	1984	466.712	607.81	963.58	123.812	2511.63	1.23266

OBS	A2	A3	A4	GR	COM	IND	OTH	PPI	RES
1	1	1.3783	1.08325	464.166	553.53	1287.41	113.085	2418.20	168.166
2	1	1.3783	1.08325	428.371	544.10	1253.10	104.720	2330.29	140.526
3	1	1.3783	1.08325	405.026	531.50	1239.60	97.751	2273.88	133.089
4	1	1.3783	1.08325	397.176	526.24	1200.69	101.121	2225.23	106.560
5	1	1.3783	1.08325	413.521	537.15	1224.22	102.873	2277.76	116.954
6	1	1.3783	1.08325	485.749	570.31	1267.62	108.307	2431.99	108.758
7	1	1.3783	1.08325	640.357	638.19	1361.58	122.429	2762.56	83.717
8	1	1.3783	1.08325	738.632	841.18	1586.71	148.608	3315.13	155.532
9	1	1.3783	1.08325	717.246	1004.06	1709.11	167.241	3597.65	183.463
10	1	1.3783	1.08325	678.143	1058.38	1757.97	174.231	3668.72	198.470
11	1	1.3783	1.08325	689.172	1096.22	1787.41	177.547	3750.35	249.876
12	1	1.3783	1.08325	702.272	1069.64	1771.61	171.408	3714.93	270.152
13	1	1.3783	1.08325	654.897	1032.15	1744.24	159.977	3591.26	245.652
14	1	1.3783	1.08325	622.728	1081.42	1808.81	162.669	3675.63	295.849
15	1	1.3783	1.08325	603.663	1046.95	1729.88	154.686	3535.18	216.906
16	1	1.3783	1.08325	666.912	956.64	1673.02	142.922	3439.50	301.956
17	1	1.3783	1.08325	808.586	891.66	1624.24	145.511	3470.00	181.811
18	1	1.3783	1.08325	946.915	795.94	1555.81	151.594	3450.26	222.401
19	1	1.3783	1.08325	922.393	767.59	1537.81	157.374	3385.17	188.467
20	1	1.3783	1.08325	894.956	811.55	1520.43	168.998	3395.93	136.904
21	1	1.3783	1.08325	870.352	783.04	1500.14	180.503	3334.04	241.207
22	1	1.3783	1.08325	842.907	721.70	1462.54	165.081	3192.23	178.800
23	1	1.3783	1.08325	763.388	670.64	1396.84	139.640	2970.51	145.916
24	1	1.3783	1.08325	575.297	607.81	1328.10	134.119	2645.33	133.699

BEST COPY

AVAILABLE

PAGE(S) 73-81

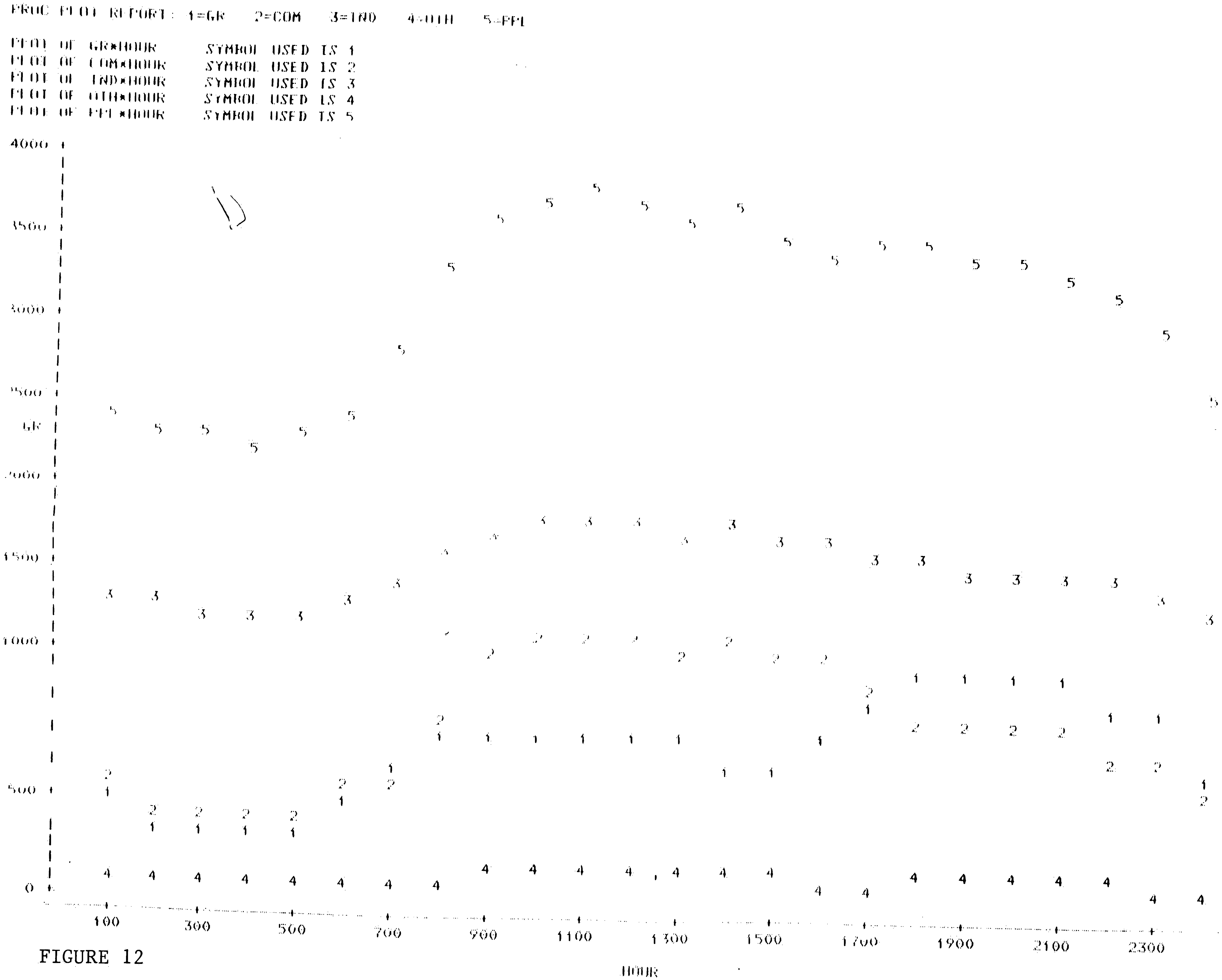

PROC PLOT REPORT: 1=GR 2=COM 3=IND 4=OTH 5=PPL
PLOT OF GR*HOUR SYMBOL USED IS 1
PLOT OF COM*HOUR SYMBOL USED IS 2
PLOT OF IND*HOUR SYMBOL USED IS 3
PLOT OF OTH*HOUR SYMBOL USED IS 4
PLOT OF PPL*HOUR SYMBOL USED IS 5
4000
3500
3000
2500
GR
2000
1500
1000
500
0
100
300
500
700
900
1100
1300
1500
1700
1900
2100
2300
HOUR

FIGURE 12

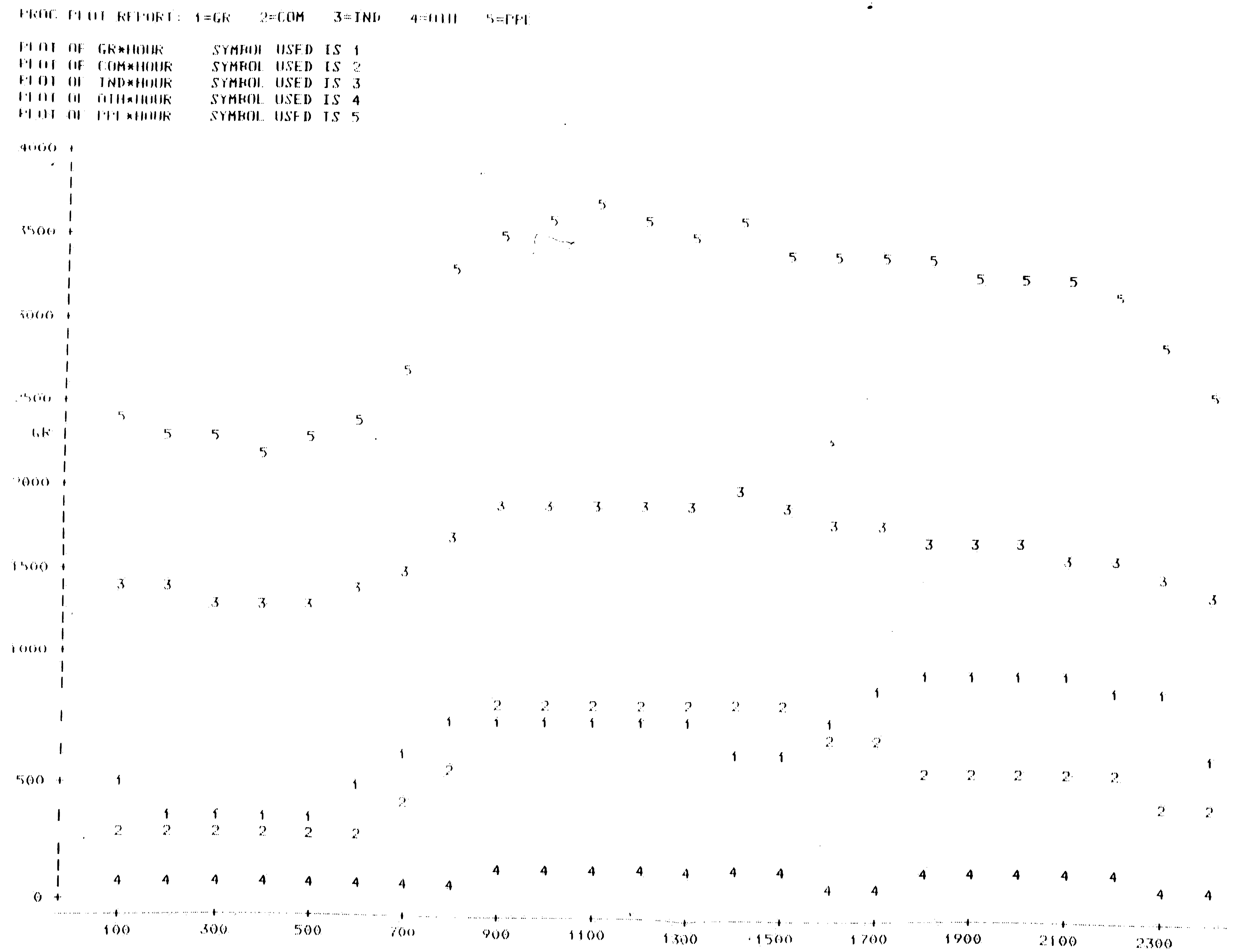
"SENSITIVITY DATA SUMMARY"

TABLE 20

DATA NEW1

OBS	HOUR	SEASON	YEAR	WDGR	WDCOM	WDIND	WDOTH	WDPPL	A1
1	100	III.SPR	1984	376.557	553.53	934.06	104.394	2250.03	1.23266
2	200	III.SPR	1984	347.518	544.10	909.16	96.672	2189.76	1.23266
3	300	III.SPR	1984	328.579	531.50	899.37	90.239	2140.79	1.23266
4	400	III.SPR	1984	322.211	526.24	871.14	93.350	2118.67	1.23266
5	500	III.SPR	1984	335.471	537.15	888.21	94.967	2160.81	1.23266
6	600	III.SPR	1984	394.066	570.31	919.70	99.983	2323.23	1.23266
7	700	III.SPR	1984	519.492	638.19	987.87	113.020	2678.84	1.23266
8	800	III.SPR	1984	599.218	841.18	1151.21	137.187	[illegible]	1.23266
9	900	III.SPR	1984	581.869	1004.06	1240.01	154.388	3414.19	1.23266
10	1000	III.SPR	1984	550.146	1058.38	1275.46	160.841	3470.25	1.23266
11	1100	III.SPR	1984	559.094	1096.22	1296.82	163.902	3500.47	1.23266
12	1200	III.SPR	1984	569.721	1069.64	1285.36	158.235	3444.78	1.23266
13	1300	III.SPR	1984	531.288	1032.15	1265.50	147.682	3345.61	1.23266
14	1400	III.SPR	1984	505.191	1081.42	1312.35	150.167	3379.78	1.23266
15	1500	III.SPR	1984	489.724	1046.95	1255.08	142.798	3318.27	1.23266
16	1600	III.SPR	1984	541.035	956.64	1213.83	131.938	3137.54	1.23266
17	1700	III.SPR	1984	655.969	891.66	1178.44	134.328	3288.19	1.23266
18	1800	III.SPR	1984	768.189	795.94	1128.79	139.941	3227.86	1.23266
19	1900	III.SPR	1984	748.295	767.59	1115.73	145.279	3196.70	1.23266
20	2000	III.SPR	1984	726.037	811.55	1103.12	156.010	3259.03	1.23266
21	2100	III.SPR	1984	706.077	783.04	1088.40	166.631	3092.83	1.23266
22	2200	III.SPR	1984	683.812	721.70	1061.12	152.394	3013.43	1.23266
23	2300	III.SPR	1984	619.302	670.64	1013.45	128.908	2824.59	1.23266
24	2400	III.SPR	1984	466.712	607.81	963.58	123.812	2511.63	1.23266

OBS	A2	A3	A4	GR	COM	IND	OTH	PPL	PLS
1	0.769463	1.5	1.08325	464.166	425.921	1401.09	113.085	2404.26	154.252
2	0.769463	1.5	1.08325	428.371	418.665	1363.74	104.720	2315.50	125.736
3	0.769463	1.5	1.08325	405.026	408.970	1349.05	97.751	2260.80	120.012
4	0.769463	1.5	1.08325	397.176	404.922	1306.71	101.121	2209.93	91.260
5	0.769463	1.5	1.08325	413.521	413.317	1332.31	102.873	2262.03	101.217
6	0.769463	1.5	1.08325	485.749	438.832	1379.55	108.307	2412.44	89.208
7	0.769463	1.5	1.08325	640.357	491.064	1481.80	122.429	2735.65	56.814
8	0.769463	1.5	1.08325	738.632	647.257	1726.81	148.608	3261.31	101.711
9	0.769463	1.5	1.08325	717.246	772.587	1860.01	167.241	3517.09	102.899
10	0.769463	1.5	1.08325	678.143	814.384	1913.19	174.231	3579.95	109.698
11	0.769463	1.5	1.08325	689.172	843.501	1945.23	177.547	3655.45	154.980
12	0.769463	1.5	1.08325	702.272	823.048	1928.04	171.408	3624.77	179.988
13	0.769463	1.5	1.08325	654.897	794.201	1898.25	159.977	3507.32	161.715
14	0.769463	1.5	1.08325	622.728	832.113	1968.52	162.669	3586.03	206.255
15	0.769463	1.5	1.08325	603.663	805.589	1882.62	154.686	3446.56	128.288
16	0.769463	1.5	1.08325	666.912	736.099	1820.74	142.922	3366.68	229.138
17	0.769463	1.5	1.08325	808.586	686.099	1767.66	145.511	3407.86	119.667
18	0.769463	1.5	1.08325	946.915	612.446	1693.18	151.594	3404.14	176.281
19	0.769463	1.5	1.08325	922.393	590.632	1673.59	157.374	3343.99	147.293
20	0.769463	1.5	1.08325	894.956	624.458	1654.68	168.998	3343.09	84.062
21	0.769463	1.5	1.08325	870.352	602.520	1632.60	180.503	3285.98	193.146
22	0.769463	1.5	1.08325	842.907	555.321	1591.68	165.081	3154.99	141.560
23	0.769463	1.5	1.08325	763.388	516.033	1520.17	139.640	2939.24	114.646
24	0.769463	1.5	1.08325	575.297	467.687	1445.37	134.119	2622.47	110.844


PROC PLOT REPORT: 1=GR 2=COM 3=IND 4=OTH 5=PPE
PLOT OF GR*HOUR SYMBOL USED IS 1
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PLOT OF IND*HOUR SYMBOL USED IS 3
PLOT OF OTH*HOUR SYMBOL USED IS 4
PLOT OF PPE*HOUR SYMBOL USED IS 5
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FIGURE 13

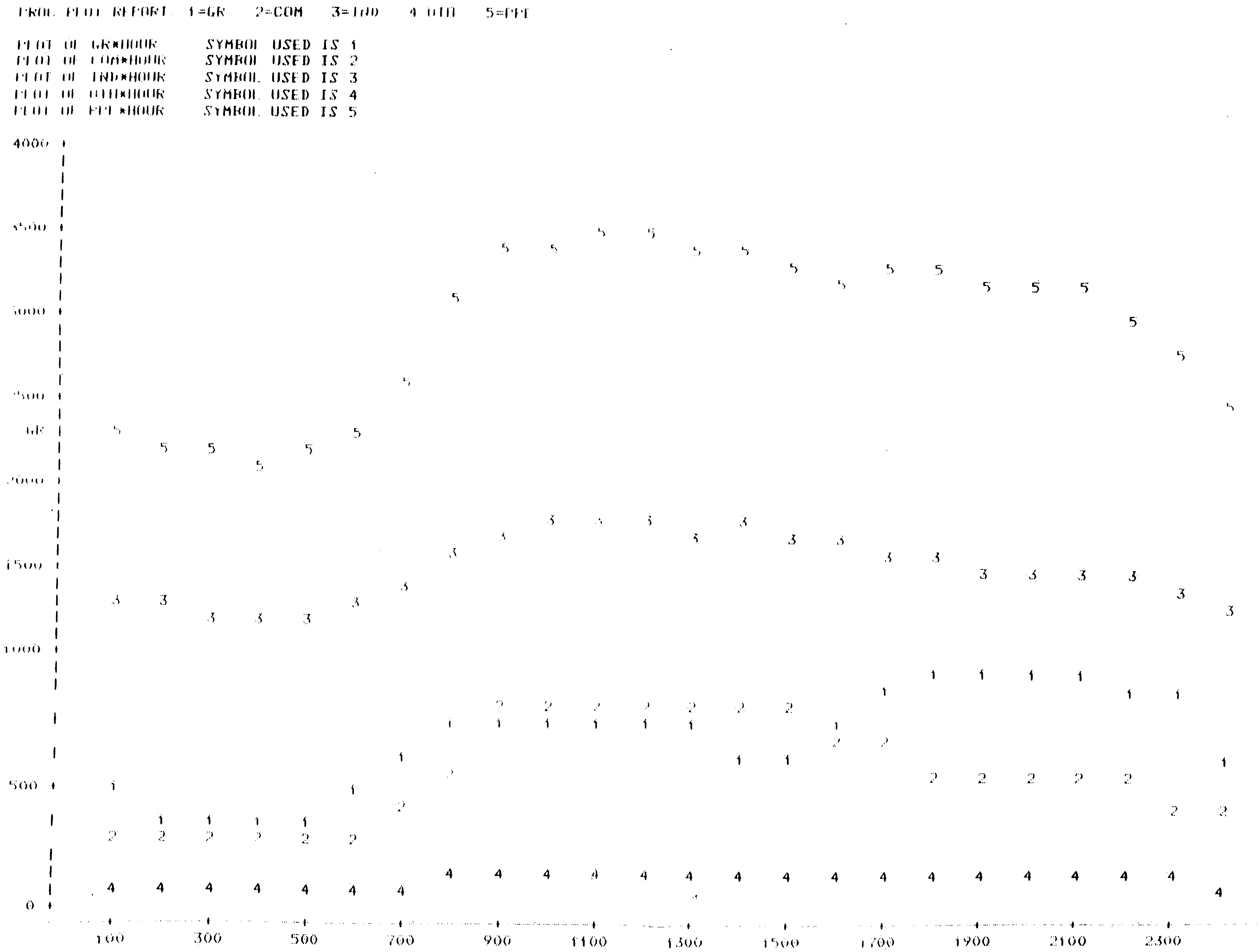
"SENSITIVITY DATA SUMMARY"

TABLE 21

DATA NEW1

OBS	HOUR	SEASON	YEAR	WDGR	WDCOM	WDIND	WDOTH	WDPFI	A1
1	100	FLLSPR	1984	376.557	553.53	934.06	104.394	2250.03	1.23266
2	200	FLLSPR	1984	347.518	544.10	909.16	96.672	2189.76	1.23266
3	300	FLLSPR	1984	328.579	531.50	899.37	90.239	2140.79	1.23266
4	400	FLLSPR	1984	322.211	526.24	871.14	93.350	2118.62	1.23266
5	500	FLLSPR	1984	335.471	537.15	888.21	94.967	2160.81	1.23266
6	600	FLLSPR	1984	394.066	570.31	919.70	99.983	2323.23	1.23266
7	700	FLLSPR	1984	519.492	638.19	987.87	113.020	2678.84	1.23266
8	800	FLLSPR	1984	599.218	841.18	1151.21	137.187	3159.60	1.23266
9	900	FLLSPR	1984	581.869	1004.06	1240.01	154.388	3414.19	1.23266
10	1000	FLLSPR	1984	550.146	1058.38	1275.46	160.841	3470.25	1.23266
11	1100	FLLSPR	1984	559.094	1096.22	1296.82	163.902	3500.47	1.23266
12	1200	FLLSPR	1984	569.721	1069.44	1285.36	158.235	3444.78	1.23266
13	1300	FLLSPR	1984	531.288	1032.15	1265.50	147.682	3345.61	1.23266
14	1400	FLLSPR	1984	505.191	1081.42	1312.35	150.167	3379.78	1.23266
15	1500	FLLSPR	1984	489.724	1046.95	1255.08	142.798	3318.27	1.23266
16	1600	FLLSPR	1984	541.035	956.64	1213.83	131.938	3137.54	1.23266
17	1700	FLLSPR	1984	655.969	891.66	1178.44	134.328	3288.19	1.23266
18	1800	FLLSPR	1984	768.189	795.94	1128.79	139.244	3227.86	1.23266
19	1900	FLLSPR	1984	748.295	767.59	1115.73	145.279	3196.70	1.23266
20	2000	FLLSPR	1984	726.037	811.55	1103.12	156.010	3259.03	1.23266
21	2100	FLLSPR	1984	706.077	783.04	1088.40	166.631	3092.83	1.23266
22	2200	FLLSPR	1984	683.812	721.70	1061.12	152.394	3013.43	1.23266
23	2300	FLLSPR	1984	619.302	670.64	1013.45	128.908	2824.59	1.23266
24	2400	FLLSPR	1984	466.712	607.81	963.58	123.812	2511.63	1.23266

OBS	A2	A3	A4	GR	COM	IND	OTH	PFI	RES
1	0.769463	1.3783	1.2	464.166	425.921	1287.41	125.273	2302.77	52.745
2	0.769463	1.3783	1.2	428.371	418.665	1253.10	116.006	2216.14	26.578
3	0.769463	1.3783	1.2	405.026	408.970	1239.60	108.287	2161.88	21.094
4	0.769463	1.3783	1.2	397.176	404.922	1200.69	112.020	2114.81	-3.859
5	0.769463	1.3783	1.2	413.521	413.317	1224.22	113.960	2165.02	4.209
6	0.769463	1.3783	1.2	485.749	438.832	1267.62	119.980	2312.18	-11.046
7	0.769463	1.3783	1.2	640.357	491.064	1361.58	135.624	2628.63	-50.215
8	0.769463	1.3783	1.2	738.632	647.257	1586.71	164.624	3137.23	-22.374
9	0.769463	1.3783	1.2	717.246	772.587	1709.11	185.266	3384.20	-29.986
10	0.769463	1.3783	1.2	678.143	814.384	1757.97	193.009	3443.50	26.748
11	0.769463	1.3783	1.2	689.172	843.501	1787.41	196.682	3516.76	16.292
12	0.769463	1.3783	1.2	702.272	823.048	1771.61	189.882	3486.81	42.034
13	0.769463	1.3783	1.2	654.897	794.201	1744.24	177.218	3370.56	24.945
14	0.769463	1.3783	1.2	622.728	832.113	1808.81	180.200	3443.85	64.073
15	0.769463	1.3783	1.2	603.663	805.589	1729.88	171.358	3310.49	-7.784
16	0.769463	1.3783	1.2	666.912	736.099	1673.02	158.326	3234.36	96.818
17	0.769463	1.3783	1.2	808.586	686.099	1624.24	161.194	3280.12	-8.067
18	0.769463	1.3783	1.2	946.915	612.446	1555.81	167.933	3283.11	55.246
19	0.769463	1.3783	1.2	922.393	590.632	1537.81	174.335	3225.17	28.470
20	0.769463	1.3783	1.2	894.956	624.458	1520.43	187.212	3227.06	-31.974
21	0.769463	1.3783	1.2	870.352	602.520	1500.14	199.957	3172.97	80.141
22	0.769463	1.3783	1.2	842.907	555.321	1462.54	182.873	3043.64	30.213
23	0.769463	1.3783	1.2	763.388	516.033	1396.84	154.690	2830.95	6.359


PROC PLOT REPORT 1=GR 2=COM 3=IND 4 OTH 5=PPT
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PLOT OF IND*HOUR SYMBOL USED IS 3
PLOT OF OTH*HOUR SYMBOL USED IS 4
PLOT OF PPT*HOUR SYMBOL USED IS 5
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FIGURE 14

"SENSITIVITY DATA SUMMARY"

TABLE 22

DATA NEW1

OBS	HOUR	SEASON	YEAR	WDGR	WDCOM	WDIND	WDOTH	WDPPL	A1
1	100	FLLSPR	1984	376.557	553.53	934.06	104.394	2250.05	0.9
2	200	FLLSPR	1984	347.518	544.10	909.16	96.672	2189.76	0.9
3	300	FLLSPR	1984	328.579	531.50	899.37	90.239	2140.79	0.9
4	400	FLLSPR	1984	322.211	526.24	871.14	93.350	2118.67	0.9
5	500	FLLSPR	1984	335.471	537.15	888.21	94.967	2160.81	0.9
6	600	FLLSPR	1984	394.066	570.31	919.70	99.983	[illegible]	0.9
7	700	FLLSPR	1984	519.492	638.19	987.87	113.020	2678.84	0.9
8	800	FLLSPR	1984	599.218	841.18	1151.21	137.187	[illegible]	0.9
9	900	FLLSPR	1984	581.869	1004.06	1240.01	154.388	3414.19	0.9
10	1000	FLLSPR	1984	550.146	1058.38	1275.46	160.841	3470.[illegible]	0.9
11	1100	FLLSPR	1984	559.094	1096.22	1296.82	163.902	3500.47	0.9
12	1200	FLLSPR	1984	569.721	1069.64	1285.36	158.235	3444.78	0.9
13	1300	FLLSPR	1984	531.288	1032.15	1265.50	147.682	3345.61	0.9
14	1400	FLLSPR	1984	505.191	1081.42	1312.35	150.167	3379.78	0.9
15	1500	FLLSPR	1984	489.724	1046.95	1255.08	142.798	3318.27	0.9
16	1600	FLLSPR	1984	541.035	956.64	1213.83	131.938	[illegible]	0.9
17	1700	FLLSPR	1984	655.969	891.66	1178.44	134.328	[illegible]	0.9
18	1800	FLLSPR	1984	768.189	795.94	1128.79	139.944	3227.86	0.9
19	1900	FLLSPR	1984	748.295	767.59	1115.73	145.279	3196.70	0.9
20	2000	FLLSPR	1984	726.037	811.55	1103.12	156.010	3259.03	0.9
21	2100	FLLSPR	1984	706.077	783.04	1088.40	166.631	3092.83	0.9
22	2200	FLLSPR	1984	683.812	721.70	1061.12	152.394	3013.43	0.9
23	2300	FLLSPR	1984	619.302	670.64	1013.45	128.908	2824.59	0.9
24	2400	FLLSPR	1984	466.712	607.81	963.58	125.812	2511.63	0.9

OBS	A2	A3	A4	GR	COM	IND	OTH	PPL	RES
1	0.769463	1.1	1.08325	338.901	425.921	1027.47	113.085	1905.57	-344.66
2	0.769463	1.1	1.08325	312.766	418.665	1000.08	104.720	1836.23	-353.53
3	0.769463	1.1	1.08325	295.721	408.970	989.31	97.751	1791.75	-349.04
4	0.769463	1.1	1.08325	289.990	404.922	958.25	101.121	1754.29	-364.38
5	0.769463	1.1	1.08325	301.924	413.317	977.03	102.873	1795.15	-365.66
6	0.769463	1.1	1.08325	354.659	438.832	1011.67	108.307	1913.47	409.76
7	0.769463	1.1	1.08325	467.543	491.064	1086.66	122.429	2167.69	-511.15
8	0.769463	1.1	1.08325	539.296	647.257	1266.33	148.608	2601.49	-558.11
9	0.769463	1.1	1.08325	523.682	772.587	1364.01	167.241	2827.52	-586.67
10	0.769463	1.1	1.08325	495.131	814.384	1403.01	174.231	2886.75	-583.50
11	0.769463	1.1	1.08325	503.185	843.501	1426.50	177.547	2950.73	549.74
12	0.769463	1.1	1.08325	512.749	823.048	1413.90	171.408	2921.10	-523.68
13	0.769463	1.1	1.08325	478.159	794.201	1392.05	159.977	2824.39	-521.22
14	0.769463	1.1	1.08325	454.672	832.113	1443.58	162.669	2893.04	486.74
15	0.769463	1.1	1.08325	440.752	805.589	1380.59	154.686	2781.61	-536.66
16	0.769463	1.1	1.08325	486.931	736.099	1335.21	142.922	2701.17	-436.37
17	0.769463	1.1	1.08325	590.372	686.099	1296.28	145.511	2718.27	569.92
18	0.769463	1.1	1.08325	691.370	612.446	1241.67	151.594	2697.08	-530.78
19	0.769463	1.1	1.08325	673.465	590.632	1227.30	157.374	2648.77	-547.93
20	0.769463	1.1	1.08325	653.433	624.458	1213.43	168.998	2660.32	-598.71
21	0.769463	1.1	1.08325	635.469	602.520	1197.24	180.503	2615.73	-477.10
22	0.769463	1.1	1.08325	615.431	555.321	1167.23	165.081	2503.07	510.36
23	0.769463	1.1	1.08325	557.372	516.033	1114.79	139.640	2327.84	-496.75
24	0.769463	1.1	1.08325	420.041	467.687	1059.94	134.119	2081.79	-429.84

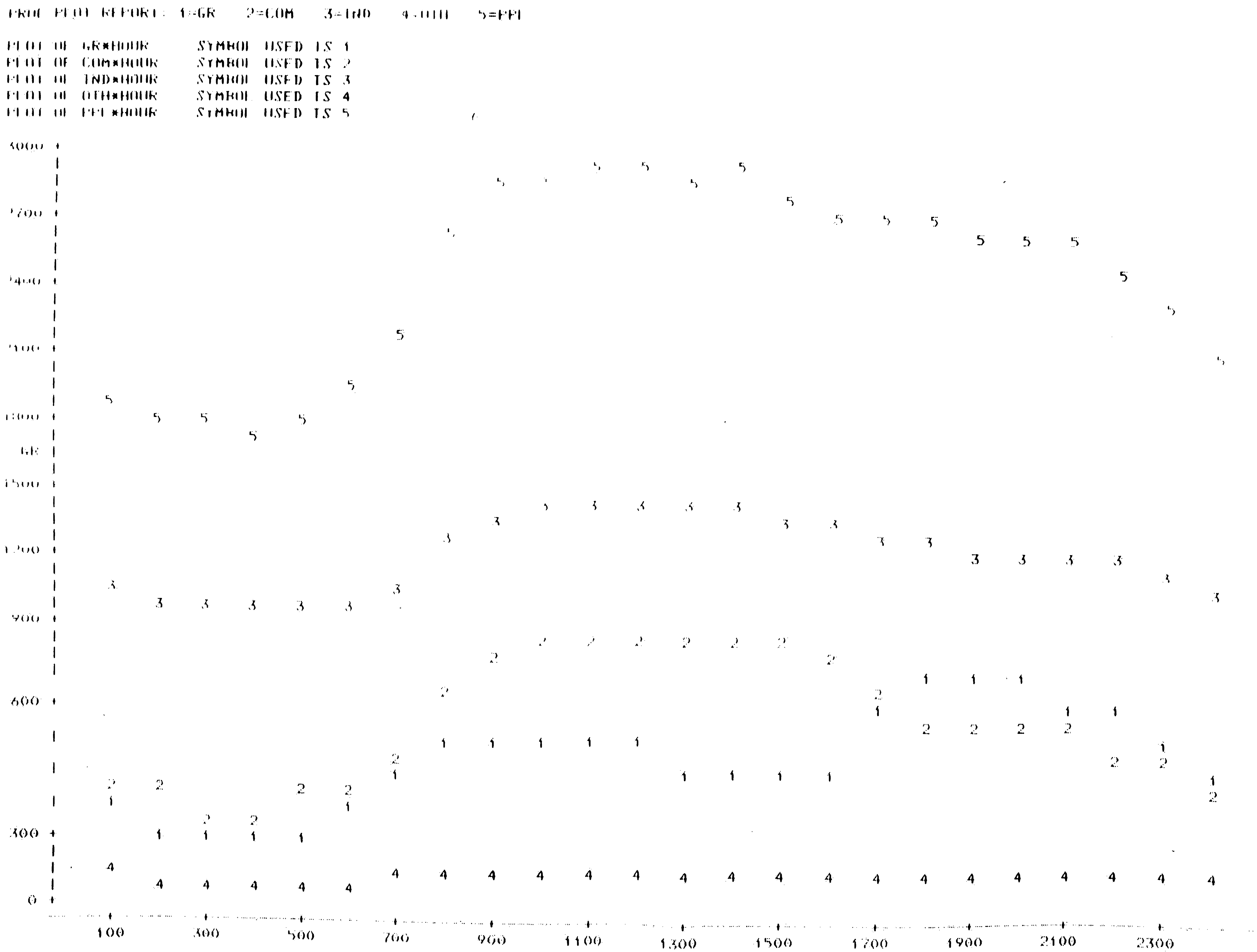
PROC PLOT REPORT: 1=GR 2=COM 3=IND 4=OTH 5=PPI
PLOT OF GR*HOUR SYMBOL USED IS 1
PLOT OF COM*HOUR SYMBOL USED IS 2
PLOT OF IND*HOUR SYMBOL USED IS 3
PLOT OF OTH*HOUR SYMBOL USED IS 4
PLOT OF PPI*HOUR SYMBOL USED IS 5

FIGURE 15

"SENSITIVITY DATA SUMMARY"

TABLE 23

Data NEW1

OBS	HOUR	SEASON	YEAR	WDGR	WDCOM	WDIND	WDOTH	WDFFL	A1	A2	A3	A4	GR	COM	IND	OTH	FFL	RES
1	100	FLLSPR	1984	376.557	553.53	934.06	104.394	2250.03	1.23266	1	1.5	1.08325	464.166	553.53	1401.09	113.085	2531.87	281.841
2	200	FLLSPR	1984	347.518	544.10	909.16	96.672	2189.76	1.23266	1	1.5	1.08325	428.371	544.10	1363.74	104.720	2440.93	251.171
3	300	FLLSPR	1984	328.579	531.50	899.37	90.239	2140.79	1.23266	1	1.5	1.08325	405.036	531.50	1349.05	97.751	2383.33	242.542
4	400	FLLSPR	1984	322.211	526.24	871.14	93.350	2118.62	1.23266	1	1.5	1.08325	397.176	526.24	1306.71	101.121	2331.25	212.578
5	500	FLLSPR	1984	335.471	537.15	888.31	94.967	2160.81	1.23266	1	1.5	1.08325	413.521	537.15	1332.31	102.873	2385.86	225.050
6	600	FLLSPR	1984	394.066	570.31	919.70	99.983	2323.23	1.23266	1	1.5	1.08325	485.749	570.31	1379.55	108.307	2543.92	220.686
7	700	FLLSPR	1984	519.492	638.19	987.87	113.020	2678.84	1.23266	1	1.5	1.08325	640.357	638.19	1481.80	122.429	2882.78	203.941
8	800	FLLSPR	1984	599.218	841.18	1151.21	137.187	3159.60	1.23266	1	1.5	1.08325	738.632	841.18	1726.81	148.608	3455.23	295.635
9	900	FLLSPR	1984	581.869	1004.06	1240.01	154.388	3414.19	1.23266	1	1.5	1.08325	717.246	1004.06	1860.01	167.241	3748.56	334.372
10	1000	FLLSPR	1984	550.146	1058.38	1275.46	160.841	3470.25	1.23266	1	1.5	1.08325	678.143	1058.38	1913.19	174.231	3823.94	353.694
11	1100	FLLSPR	1984	559.094	1096.22	1296.82	163.902	3500.47	1.23266	1	1.5	1.08325	689.172	1096.22	1945.23	177.547	3908.17	407.699
12	1200	FLLSPR	1984	569.721	1069.64	1285.36	158.235	3444.78	1.23266	1	1.5	1.08325	702.272	1069.64	1928.04	171.408	3871.36	426.580
13	1300	FLLSPR	1984	531.288	1032.15	1265.50	147.682	3345.61	1.23266	1	1.5	1.08325	654.897	1032.15	1898.25	159.977	3745.27	399.664
14	1400	FLLSPR	1984	505.191	1081.42	1312.35	150.167	3379.78	1.23266	1	1.5	1.08325	622.728	1081.42	1968.52	162.669	3835.34	455.562
15	1500	FLLSPR	1984	489.724	1046.95	1255.08	142.798	3318.27	1.23266	1	1.5	1.08325	603.663	1046.95	1882.62	154.686	3687.92	369.649
16	1600	FLLSPR	1984	541.035	956.64	1213.83	131.938	3137.54	1.23266	1	1.5	1.08325	666.912	956.64	1820.74	142.922	3587.22	449.679
17	1700	FLLSPR	1984	655.969	891.66	1178.44	134.328	3288.19	1.23266	1	1.5	1.08325	808.586	891.66	1767.66	145.511	3613.42	325.227
18	1800	FLLSPR	1984	768.189	795.94	1128.79	139.944	3227.86	1.23266	1	1.5	1.08325	946.915	795.94	1693.18	151.594	3587.63	359.775
19	1900	FLLSPR	1984	748.295	767.59	1115.73	145.279	3196.70	1.23266	1	1.5	1.08325	922.393	767.59	1673.59	157.374	3520.95	324.251
20	2000	FLLSPR	1984	726.037	811.55	1103.12	156.010	3259.03	1.23266	1	1.5	1.08325	894.956	811.55	1654.68	168.998	3530.18	271.154
21	2100	FLLSPR	1984	706.077	783.04	1088.40	166.631	3092.83	1.23266	1	1.5	1.08325	870.352	783.04	1632.60	180.503	3466.50	373.666
22	2200	FLLSPR	1984	683.812	721.70	1061.12	152.394	3013.43	1.23266	1	1.5	1.08325	842.907	721.70	1591.68	165.081	3321.37	307.938
23	2300	FLLSPR	1984	619.302	670.64	1013.45	128.908	2824.59	1.23266	1	1.5	1.08325	763.388	670.64	1520.17	139.640	3093.84	269.253
24	2400	FLLSPR	1984	466.712	607.81	963.58	123.812	2511.63	1.23266	1	1.5	1.08325	575.297	607.81	1445.37	134.119	2762.60	250.966

PROC PLOT REPORT 1=GR 2=COM 3=IND 4=OTH 5=PPL

PLOT OF GR*HOUR SYMBOL USED IS 1
PLOT OF COM*HOUR SYMBOL USED IS 2
PLOT OF IND*HOUR SYMBOL USED IS 3
PLOT OF OTH*HOUR SYMBOL USED IS 4
PLOT OF PPL*HOUR SYMBOL USED IS 5

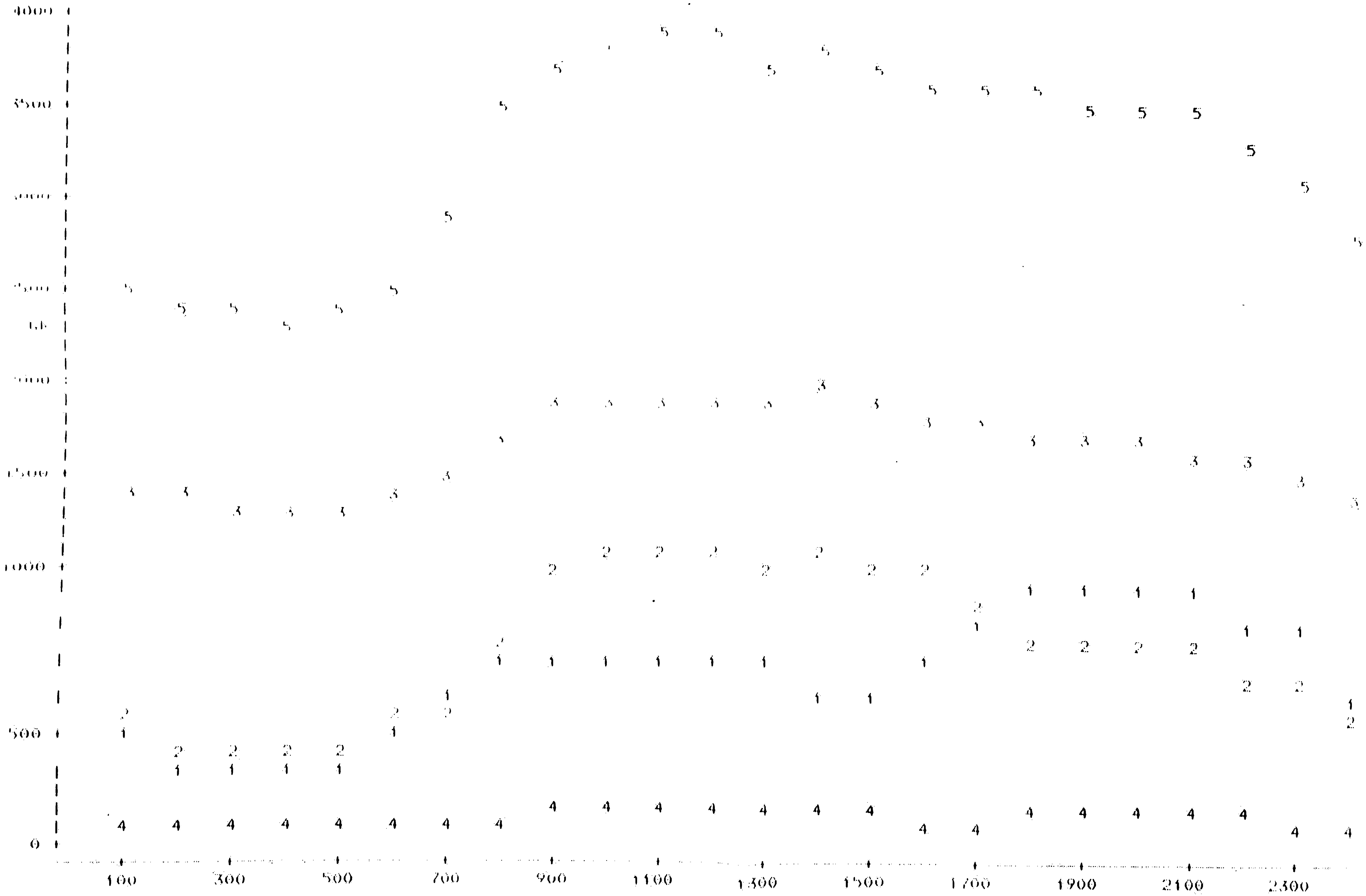

FIGURE 16

Optimal Mix

Study 1

The optimal mix problem was discussed in Chapter III using a linear programming procedure. The price coefficients and right hand side constants were derived from various utility tariffs in the load groups for residential, commercial and industrial. Tables 24 through 30 show the specific tariffs utilized and the equations used in the linear programming procedure. A 3500 MW peak was used from the previous state estimation problem. The results are shown in Tables 31 through 34. These results clearly indicate that the optimal mix should include primarily the commercial and industrial loads. Further, the reduced cost associated with each variable is the marginal value of that variable if it is brought into the basis. Consequently, for a maximization problem, basic variables have a zero reduced cost at optimality. On the other hand, nonbasic variables that are not at an upper bound, have nonpositive reduced costs. This shows the objective would decrease if they were to increase beyond their optimal value.

Study 2

This study examined the sensitivity of the solution to changes in the right-hand side constants. The results can be seen in Tables 35 through 39. Overall, there is little effect to the objective value. Clearly, sensitivity can be changed by the pricing coefficients. The possibilities are endless. Chapter V will summarize the conclusions and present some recommendations.

TABLE 24

GENERAL SERVICE WITH ELECTRIC SPACE HEATING

Single meter general service for all customer's energy requirements.
(Limited to customers served as of 1/29/70)

NET MONTHLY RATE

$15.00 Per Month
$ 1.00 Per KW

5.6¢ Per KWH

MINIMUM MONTHLY BILL $15.00

MONTHLY FORMULAS

KWH Range	KW Charge	KWH Charge	Fixed Charge
All KWH	$1.00	$.056	$15

Time-of-Day metering and billing is available at an additional charge of $12.00/Month for a minimum of one (1) year.

1. Current Pa. TAX SURCHARGE must be added to all Net Bills. TAX SURCHARGE is NOT applicable to ENERGY COST RATE REVENUE.
2. Current ENERGY COST RATE must be applied to all KWH.
3. A NEGATIVE ENERGY COST RATE shall not be applied to KWH when billed minimum.

TABLE 25

SEPARATE METER GENERAL SPACE HEATING SERVICE

Separately metered space heating service to customers supplied under another General Service Rate Schedule. (Limited to customers served as of 8/21/72)

NET MONTHLY RATE

$15.00 includes 200 KWH

5.9¢ per KWH excess KWH

MINIMUM MONTHLY BILL **$15.00**

MONTHLY FORMULAS

KWH Range	KWH Charge	Fixed Charge
0-200	$ --	$15.00
Over 200	.059	3.20

1. Current Pa. TAX SURCHARGE must be added to all Net Bills. TAX SURCHARGE is NOT applicable to ENERGY COST RATE REVENUE.
2. Current ENERGY COST RATE must be applied to all KWH.
3. A NEGATIVE ENERGY COST RATE shall not be applied to KWH when billed minimum.

TABLE 26

NET MONTHLY RATE

$6.65 per KW first 125 KW
4.35 per KW Excess KW

5.0¢ per KWH first 150 KWH/KW
4.4¢ per KWH next 100 KWH/KW
3.8¢ per KWH excess KWH

MINIMUM BKW 25

MONTHLY FORMULAS

25 125 KW			Over 125 KW		
KW Charge	KWH Charge	Fixed Charge	KW Charge	KWH Charge	Fixed Charge
$6.65	$.050	$ -	$4.35	$.050	$287.50
7.55	.044	-	5.25	.044	287.50
9.05	.038	-	6.75	.038	287.50

Time-Of-Day metering and billing is available at an additional charge of $12.00/month for a minimum of one (1) year.

1. Current Pa. TAX SURCHARGE must be added to all Net Bills. TAX SURCHARGE is NOT applicable to ENERGY COST RATE REVENUE.
2. Current ENERGY COST RATE must be applied to all KWH.
3. A NEGATIVE ENERGY COST RATE shall not be applied to KWH when billed minimum.

TABLE 27

SINGLE METER COMMERCIAL SPACE HEATING SERVICE

Single Meter commercial service for all of customer's energy requirements, including space heating. (limited to customers served as of 8/21/72)

NET MONTHLY RATE

$15.00 per Month
$ 1.00 per KW

7.5¢ Per KWH First 2,500 KWH
6.0¢ Per KWH Next 100 KWH/KW
5.6¢ Per KWH Excess KWH

MINIMUM MONTHLY BILL $15.00

MONTHLY FORMULAS

KWH Range		KW	KWH	Fixed
From	To	Charge	Charge	Charge
0	2500	$1.00	$.075	$15.00
2501	100 x BKW + 2500	1.00	.060	52.50
100 x BKW + 2501	--	1.40	.056	62.50

Time-Of-Day metering and billing is available at an additional charge of $12.00/Month for a minimum of one (1) year.

1. Current Pa. TAX SURCHARGE must be added to all Net Bills. TAX SURCHARGE is NOT applicable to ENERGY COST RATE REVENUE.
2. Current ENERGY COST RATE must be applied to all KWH.
3. A NEGATIVE ENERGY COST RATE shall not be applied to KWH when billed minimum.

TABLE 28

NET MONTHLY RATE

$4.40 Customer Charge
7.6¢ per KWH First 200 KWH
5.6¢ per KWH Excess KWH

Number of Dwelling Units	Rate Schedule Code	7.6¢ Block KWH Range	7.6¢ Block $.076 All KWH Plus	5.6¢ Block KWH Range	5.6¢ Block $.056 All KWH Plus
1	RS	0-200	$ 4.40	Over 200	$ 8.40
2	RS	0-400	8.80	Over 400	16.80
3	RS	0-600	13.20	Over 600	25.20
4	RS	0-800	17.60	Over 800	33.60

1. Current Pa. TAX SURCHARGE must be added to all Net Bills. TAX SURCHARGE is NOT applicable to ENERGY COST RATE REVENUE.
2. The current ENERGY COST RATE must be applied to all KWH.
3. A NEGATIVE ENERGY COST RATE shall not be applied to KWH when billed minimum.

TABLE 29

NET MONTHLY RATE

$3.30 per KW

4.0¢ per KWH first 150 KWH/KW
3.6¢ per KWH next 100 KWH/KW
3.2¢ per KWH excess KWH

MINIMUM BKW 10,000

MONTHLY FORMULAS

$\geq$ 10,000 KW

KW Charge	KWH Charge
$3.30	$.040
3.90	.036
4.90	.032

In addition to the above charges, for 25 cycle service there is a charge of $3,450/month for use of company facilities.

Time-Of-Day metering and billing is available at an additional charge of $12.00/Month for a minimum of one (1) year.

1. Current Pa. TAX SURCHARGE must be added to all Net Bills. TAX SURCHARGE is NOT applicable to ENERGY COST RATE REVENUE.
2. Current ENERGY COST ADJUSTMENT must be applied to all KWH.
3. A NEGATIVE ENERGY COST ADJUSTMENT shall not be applied to KWH when billed minimum.

TABLE 30

RATE SCHEDULE EQUATION SUMMARY

GH-4(R) Residential

$15 + 1.00(X_1) + .056(X_1) = 15 + 1.056(X_1)$

No Limit on X_1

GH - 2(R) Residential

$15 + .059(X_2) + 3.20(X_2 > 200)$

$X_2 > 200$

GS - 3 Commercial

$166 + .05(X_4) + .044(X_5) + 4.35(X_5) + .038(X_6 + 4.35(X_6)$

+287.50

$25 \leq X_4 \leq 275$ $275 \leq X_5 \leq 375$ $375 < X_6$ If

$X > 125$

GH - 1(R) Commercial

$15 + 1.075(X_7) + 52.50 + 1.06(X_8) + 62.50 + 1.456(X_9)$

$X_7 \geq 2500$ $2501 \leq X_8 \leq 2600$ $X_9 > 2601$

RS Residential

$4.40 + .076(X_{10}) + .056(X_{11})$

$200 \leq X_{10}$ $X_{11} > 200$

LP - 6

$$3.34 \qquad\qquad 3.936 \qquad\qquad 4.932$$

$$[3.30(X_{24})+.040(X_{24})] + [3.90(X_{25})+.036(X_{25})] + [4.90(X_{26}) + .032(X_{26})]$$

$$10{,}000 \leq X_{24} \leq 10{,}150 \qquad 10150 < X_{25} \leq 10{,}250 \qquad X_{26} > 10{,}250$$

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TABLE 31

SAS

LINEAR PROGRAMMING PROCEDURE

PROBLEM SUMMARY

MAX _OBS1_	OBJECTIVE FUNCTION	
VALUE	RHS VARIABLE	
TYPEID	TYPE VARIABLE	
PROBLEM DENSITY	0.097	

VARIABLE TYPE	NUMBER
STRUCTURAL	
NONEGATIVE	11
LOGICAL	
SLACK	7
SURPLUS	9
TOTAL	27

CONSTRAINT TYPE	NUMBER
LE	7
GE	9
FREE	1
TOTAL	[illegible]

TABLE 32

SAS

L I N E A R   P R O G R A M M I N G   P R O C E D U R E

SOLUTION SUMMARY

TERMINATED SUCCESSFULLY

OBJECTIVE VALUE	17206272
PHASE 1 ITERATIONS	9
PHASE 2 ITERATIONS	2
INITIAL B.F. VARIABLES	7
TIME USED (SECS)	0.[illegible]
NUMBER OF INVERSIONS	3
MACHINE EPSILON	1.00000[illegible]
MACHINE INFINITY	7.23701E+75
INVERT FREQUENCY	50
MAX PHASE 1 ITERATIONS	100
MAX PHASE 2 ITERATIONS	100
TIME LIMIT (SECS)	120.00

TABLE 33

SAS

L I N E A R   P R O G R A M M I N G   P R O C E D U R E

VARIABLE SUMMARY

COL	VARIABLE NAME	[illegible]				REDUCED
1	R1		NON-NEG	1.056	0	3.876000
2	R[illegible]	[illegible]				
3	R3		NON-NEG	0.076	0	-4.856000
4	C1	BASIC	NON-NEG	4.394	275.000	0
5	C2	BASIC	NON-NEG	4.388	375.000	0
6	C3	BASIC	NON NEG	1.075	2500.000	0
7	C4	BASIC	NON NEG	1.06	2501.000	0
8	C5	BASIC	NON-NEG	[illegible]		
9	I1	BASIC	NON-NEG	3.34	1[illegible]	
10	I2	BASIC	NON-NEG	3.936	10150.000	0
11	I3	BASIC	[illegible]			0
12	_OBS2_	BASIC	SLACK	0	3500000	0
13	_OBS3_		SURPLUS	0	0	-4.873000
14	_OBS4_	BASIC	SLACK	0	200.000	0
15	_OBS5_		SURPLUS	0	0	0.538000
16	_OBS6_	BASIC	SLACK	0	1[illegible]	
17	_OBS7_		SURPLUS	0	0	-0.544000
18	_OBS8_		SURPLUS	0	0	[illegible]
19	_OBS9_		SURPLUS	0	0	3.872000
20	[illegible]			0		
21	_OBS11_		SURPLUS	0	0	-3.476000
22	_OBS12_		SURPLUS	0	0	1.592000
23	_OBS13_	BASIC	SLACK	0	150.000	0
24	_OBS14_		SURPLUS	0	0	-0.996000
25	_OB[illegible]			[illegible]		
26	_OBS16_	BASIC	SURPLUS	0	3461147	0
27	_OB[illegible]		SLACK	0	0	4.[illegible]

TABLE 34

SAS

L I N [illegible] A R   P R O G R A M M I N G   P [illegible]

CONSTRAINT SUMMARY

CON[illegible] ROW	ID	TYPE	S[illegible] COL	RHS	ACTIVITY	D[illegible] ACTIVITY
1	_OBS2_	LE	12	3500000	0	0
2	_OBS3_	GE	13	201.000	201.000	4.873000
3	_OBS4_	LE	14	200[illegible]	0	0
4	_OBS5_	GE	15	275.000	275.000	0.538000
5	_OB[illegible]	[illegible]				
6	_OBS7_	GE	17	375.000	375.000	-0.544000
7	_OBS8_	GE	18	[illegible]		
8	_OBS9_	GE	19	2501.000	2501.000	3.872000
9	_OBS10_	LE	20	2600.000	2501.000	0
10	_OBS11_	GE	21	2601.000	2601.000	3.476000
11	_OBS12_	GE	22	10000.000	10000.000	1.592000
12	_OB[illegible]					
13	_OBS[illegible]	GE	24	10[illegible]		
14	_OBS15_	LE	25	10250.000	10150.000	0
15	_OB[illegible]	GE	26	10[illegible]0.000	3471397	0
16	_OBS17_	LE	27	3500000	3500000	4.932000
17	_OBS1_	OBJECTIVE		17206272	17206272	0

TABLE 35

SAS

L I N E A R   P R O G R A M M I N G   P R O C E D U R E

[illegible]

MAX _OBS1_	OBJECTIVE FUNCTION
VALUE	RHS VARIABLE
TYPEID	TYPE VARIABLE
PROBLEM [illegible]	0.0[illegible]

VARIABLE TYPE	NUMBER
STRUCTURAL	
NONEGATIVE	11
LOGICAL	
SLACK	7
SURPLUS	9
TOTAL	27

CONSTRAINT TYPE	NUMBER
LE	7
GE	9
FREE	1
TOTAL	17

TABLE 36

SAS

LINEAR PROGRAMMING PROCEDURE

SOLUTION SUMMARY

TERMINATED SUCCESSFULLY

OBJECTIVE VALUE	17206.272
PHASE 1 ITERATIONS	9
PHASE 2 ITERATIONS	2
INITIAL B.F. VARIABLES	7
TIME USED (SECS)	0.00
NUMBER OF INVERSIONS	3
MACHINE EPSILON	1.00[illegible]
MACHINE INFINITY	7.23[illegible]
INVERT FREQUENCY	50
MAX PHASE 1 ITERATIONS	100
MAX PHASE 2 ITERATIONS	100
TIME LIMIT (SECS)	120.00

TABLE 37

SAS

L I N E A R   P R O G R A M M I N G   P R O C E D U R E

VARIABLE SUMMARY

COL	VARIABLE NAME					REDUCED
1	R1		NON NEG	1.056	0	3.876000
2	R2	[illegible]	[illegible]			
3	R3		NON NEG	0.076	0	-4.856000
4	[illegible]	[illegible]	N NE[illegible]			
5	C2	BASIC	NON NEG	4.388	375.000	0
6	C3	BASIC	NON NEG	1.075	2500.000	0
7	C4	BASIC	NON-NEG	1.06	2501.000	0
8	C5	BASIC	NON NEG	1.456	2601.000	0
9	I1	BASIC	NON NEG	3.3[illegible]		
10	I2	BASIC	NON-NEG	3.936	10150.000	0
11	I[illegible]	[illegible]				
12	_OBS2_	BASIC	SLACK	0	3500000	0
13	[illegible]		[illegible]	0	0	[illegible]
14	_OBS4_	BASIC	SLACK	0	200.000	0
15	_OBS5_		SURPLUS	0	0	-0.538000
16	_OBS6_	BASIC	SLACK	0	100[illegible]	0
17	_OBS7_		SURPLUS	0	0	-0.544000
18	[illegible]		[illegible]	0	[illegible]	[illegible]
19	_OBS9_		SURPLUS	0	0	-3.872000
20	_OBS10_	[illegible]	[illegible]	0	[illegible]	[illegible]
21	_OBS11_		SURPLUS	0	0	-3.476000
22	[illegible]		[illegible]	0	0	[illegible]
23	_OBS13_	BASIC	SLACK	0	150.000	0
24	_OBS14_		SURPLUS	0	0	-0.996000
25	_OBS15_	BASIC	SLACK	0	1[illegible]	
26	_OBS16_	BASIC	SURPLUS	0	3461147	0
27	[illegible]		SL[illegible]	0		

TABLE 38

SAS

L I N [illegible]

CONSTRAINT SUMMARY

ROW	ID	TYPE	CON. COL	RHS	ACTIVITY	ACTIVITY
1	_OB[illegible]	[illegible]	[illegible]		[illegible]	[illegible]
2	_OBS3_	GE	13	201.000	201.000	4.873000
3	_OBS4_	LE	14	200[illegible]	[illegible]	0
4	_OBS5_	GE	15	275.000	275.000	0.538000
5	_OBS6_	LE	16	375.000	275.000	0
6	_OBS7_	GE	17	375.000	375.000	0.544000
7	_OBS8_	GE	18	[illegible]		
8	_OBS9_	GE	19	2501.000	2501.000	3.872000
9	_OB[illegible]					
10	_OBS11_	GE	21	2601.000	2601.00[illegible]	
11	_OBS12_	GE	22	10000.000	10000.000	1.592000
12	_OBS13_	LE	23	10150.000	10000.000	0
13	_OBS14_	GE	24	10150.000	10150.000	0.[illegible]
14	_OBS15_	LE	25	10250.000	10150.000	0
15	_OB[illegible]	LE	[illegible]			
16	_OBS17_	LE	[illegible]			
17	_OBS1_	OBJECTIVE		17206272	17206272	0

TABLE 39

SA

L I N E A R   P R O G R A M M I N G   P R O C E D U R E

RH

SENSITIVITY VECTOR RSEN

MINIMUM PHI	0.1[illegible]
LEAVING VARIABLE	_OBS6
OPTIMAL OBJECTIVE	142479[illegible]
MAXIMUM PHI	+INFINITY

COL	VARIABLE NAME	ACTIVITY AT MIN PHI	ACTIVITY AT MAX PHI
1	R1	0	0
2	R2	201.000	201.000
3	R3	0	0
4	C1	275.000	275.000
5	C2	275.000	[illegible]
6	C3	2450.000	+INFINITY
7	C4	2451.000	+INFINITY
8	C5	2551.000	+INFINITY
9	I1	9900.000	+INFINITY
10	I2	10050.000	+INFINITY
11	I3	2871847	+INFINITY
12	_OBS2_	2900000	+INFINITY
13	_OBS3_	0	0
14	_OBS4_	200.000	200.000
15	_OBS5_	0	0
16	_OBS6_	0	+INFINITY
17	_OBS7_	0	0
18	_OBS8_	0	0
19	_OBS9_	0	0
20	_OBS10_	99.000000	99.000000
21	_OBS11_	0	0
22	_OBS12_	0	0
23	_OBS13_	150.000	150.000
24	_OBS14_	0	0
25	_OBS15_	100.000000	100.000000
26	_OBS16_	2861697	+INFINITY
27	_OBS17_	0	0

Chapter V

Conclusions and Recommendations

Demand (Load) Planning

Future demand for electricity has been treated traditionally as a predetermined quantity by utility planners. Their job has been to estimate that quantity, then plan supply accordingly. But the energy disruptions of the 1970s put a crimp in this familiar process. Predictable demand and flexible low-cost supply, the prerequisites of traditional planning, became harder and harder to achieve.

So the natural questions emerged: Why keep treating demand as fixed? Why not work with demand as well as supply to make a match? The result has been a new utility emphasis on demand-side planning. And actively planning demand is quite different from predicting what demand will be. About 300 utilities nationwide already run some 1000 separate projects aimed at shaping future demand, although not all are the product of formal planning.[9] Estimates show that nearly 50% of the nation's utilities are actively engaged in some form of demand-side planning.[7] The projects are not limited to a particular kind of utility or a particular geographic region. The approach applies equally well to large and small, municipal and investor-owned, urban and rural utilities across the country.

Demand-side planning carefully pinpoints utility actions that can change customer demand in mutually beneficial ways. For example, a planning analysis for a certain utility may show that offering interest-free loans for home insulation will be cost-effective by reducing the utility's demand peaks and its customers' energy bills. In response to a need evident since the groundswell of demand-side activity in the late 1970s, formal planning brings a systematic approach to the selection of the most cost-effective action or combination of actions for a given utility.

Although the emphasis on structured planning is a recent development, efforts to influence the demand for electricity are as old as the utility industry itself. Back in the 1890s in New York City, virtually the only load at Thomas A. Edison's Pearl Street generating facility was nighttime lighting.[9] So he hired people to find and promote daytime uses for electricity. The electric motor, then a fledgling technology, was a perfect candidate, and utility loads grew around the clock as electric motors began taking over the heavy work in industry, business, and homes.

These two examples make an important point about demand-side activity: It is not just for reducing loads or just for building loads. It involves both - and all the load redistribution options in between. For utilities with strong load growth, curtailing demand can defer the need for costly new construction. For those with ample reserve margins, building load can improve the return on investments already made. Even those utilities with a good overall match between capacity and demand can cut operating costs by redistributing demand more evenly throughout the hours of the day or the days of the year.

In this more comprehensive approach to utility planning, the planner must first identify broad utility goals. Say that one such goal is improved financial performance. The next step is defining tactical objectives, such as construction deferral or increased revenues, that will bring the utility closer to that goal. The process then narrows down to translating these tactical objectives into desired load shapes.

Formal demand-side planning targets specific load shape objectives. Although the possibilities for changing load shapes are infinite, five general types of change illustrate the range. The first three are classic load management techniques for improving utility load curves by smoothing out the peaks and valley of customer demand. Peak clipping reduces system peak loads, valley filling builds off-peak loads, and load shifting moves demand from on-peak to off-peak periods.

Another possibility, strategic conservation, reduces total energy use without necessarily reducing peak demand. In choosing this objective, the utility planner takes into account the conservation actions that would occur naturally and then evaluates the cost-effectiveness of utility programs to stimulate or accelerate those actions. The fifth possibility for changing a utility's load profile is strategic load growth, which means an increase in beneficial sales.

In the last two cases the strategic aspect is selectivity. Such objectives are pursued only in carefully chosen end-use markets where load changes would benefit both utility and customer.

Once the utility has targeted its load shape objectives, what then? Under the demand-side umbrella the planner can find a diverse group of options for meeting those objectives: load management, strategic conservation, customer generation, innovative rates, industrial electrification, new uses for electricity in the residential and commercial sectors, and adjustments in market share. What they all have in common is the potential to alter utility load shapes.

Choosing just the right option or combination of options to do this effectively is the next step in the planning process.

Trimming and Shaping Loads

Load management addresses the need to improve plant utilization by making customer demand more complementary over time to the available capacity. Perhaps the most familiar form is direct utility control of customer appliances to clip system peaks. A recent nationwide survey of utility end-use projects (EM-3529) shows more than a fivefold increase in utility load control projects between 1977 and 1983. Further, nearly 75% of these projects are now classified as broad-based implementations rather than tests, whereas the split was nearly even as recently as 1981.

The 218 utility load control projects reported in the survey involve more than 1.5 million separate loads. Most of them are residential, with electric water heaters (650,000) and central air conditioners (515,000) topping the list. Other applications include residential spare heating systems (50,000), swimming pool pumps (260,000), and irrigation pumps (14,000). More than 85% are directly utility-controlled by installation of a remote communications link, such as a radio, ripple, or power line carrier. The remainder use "smart" controllers, which are set according to utility parameters or depend on customer self-control in response to some incentive offered by the utility.

Minnkota Power Cooperative, which supplies 12 rural electric cooperatives in Minnesota and North Dakota, has relied on demand-side planning to select those options that will be most cost-effective in softening its severe winter peak and boosting its annual load factor.[20] One choice has been load control by means of dual-fuel space heating. Minnkota's roughly 15,000 dual-fuel systems, which add electric resistance heaters to oil-burning space heaters, are designed to operate on electricity 90% of the time and on oil 10% of the time. When demand on the utility begins to peak, Minnkota operators switch these directly controlled customer heating systems from electricity to oil. Average demand reduction is about 8 kW per load. Although these systems account for the majority of the utility's 220-MW load-shedding capability. Customers suffer no discomfort from the switch, and the utility is able to maintain a competitive stance and build off-peak load while clipping its winter demand peak.

The results of this and other carefully planned demand-side activities at Minnkota show a dramatic improvement in annual load factor - from a low of 48% in 1976 to 63% by 1983.[20]

Sales and revenues are up, while rates remain at least 36% lower than they would have been without these efforts. The average Minnkota customer saves about $400 a year on energy bills.[20]

Conservation is another demand-side option for the utility planner. Although most utilities in the United States have instituted some sort of conservation services for their customers, those finding themselves short of critical fuels or generating capacity have pursued this option more vigorously. Northwestern utilities that rely on hydropower turned to conservation when water resources became strained, and the oil pinch forced many northeastern utilities to make similar demand-side moves. Financing or regulatory constraints that cramp capacity growth often have the same effect.

Thirteen utilities participated in a recently completed conservation study (EA-3585). Their 187 conservation programs provide information, direct technical assistance, financial incentives, special rates, and demonstrations to customers. For example, Pacific Gas and Electric Co. uses bill inserts promoting a variety of energy-saving devices for the home. Florida Power & Light Co. provides direct technical assistance in the form of pool pump audits and adjustments for owners of the estimated 216,000 swimming pools in its service area. Northeast Utilities, like many in this group, offers low-interest loans to customers for weatherization. Duke Power Co. offers a special conservation rate, 12-14% below the average space-heating rate, to residential customers who meet insulation requirements. And the Tennessee Valley Authority has been very active in demonstrating energy-saving solar technologies in its service area.

Promoting customer generation of electricity is another demand-side option planners can choose to relieve the strain on utilities that are hard pressed to keep up with demand growth. The idea is to shift some of the burden of investment in power generation equipment from the utility to the user. Possible candidates range from rural customers who generate small amounts of power from their own windmills to large manufacturing concerns that cogenerate electricity with process steam from a common fuel source. Some are self-sufficient, but most maintain a relationship with the local utility, buying backup power when they need it and/or selling their surplus power to the utility grid.

Nowhere in demand-side planning is the influence of utility rate structures more evident than in the case of customer generation. If utilities pay high prices for customer power and charge low rates for backup, they encourage customer generation. Low purchase rates and high backup rates have the opposite effect. Under the Public Utility Regulatory Policies Act (PURPA) of 1978, the federal government has mandated state procedures that result in purchase rates encouraging customer generation.

Innovative rates stimulate various types of customer behavior, and they play an important role in many other areas of demand-side planning as well. One of the most familiar examples is the time-of-use (TOU) rate. The first utility TOU meter was patented back in the late 1980s, but only in the past decade have electric utilities begun experimenting with TOU rates on a large scale. Utilities can use the TOU rate to shift loads by rewarding customers for using electricity during off-peak rather than on-peak hours. According to a recent survey, 106 utilities now offer TOU rates (EA-3830). General Public Utilities Corp., with more than 31,000 customers on TOU rates, is one of the leaders in this field.

Interruptible service rates are yet another innovation, one that 86 utilities nationwide are trying. The industrial customer agrees to an interruption of service, usually with advance notice, at times when the utility finds it necessary to clip system peaks. Commonwealth Edison Co. of Chicago has offered both interruptible service rates and favorable rates to industrial cogenerators in support of its demand-side planning objectives - in this case, controlling demand peaks and deferring the need for any new capacity beyond that already under construction.

The foregoing options that reduce or control loads are important for planners working to improve financial performance and hold down costs to customers. Increasingly, however, planners are blending their load-restraining programs with selective efforts to build loads. Sometimes the effort focuses on filling valleys in the utility load curve. Other times the emphasis in on strategic load growth (increasing the utility's total sales).

The objective is to use existing generating capacity and achieve a reasonable return on the investment that it represents. With capacity margins what they are, some utilities are not earning revenue to amortize all of the capital. The money that they have invested in generating capacity is not yielding enough revenue to provide adequate cash flow.

One solution to this bind is to raise rates. But this is neither popular with customers nor always effective. Another solution is to take an active role in influencing demand.

Building Loads

Three remaining options under the demand-side umbrella are of special interest to those planners whose load shape objectives include valley filling and/or load growth: industrial electrification, new uses for electricity in the residential and commercial sectors, and adjustments in market share.

The trend is toward increasing use of electrically based processes in the industrial sector because of the great boosts in productivity that electrotechnologies can provide. For example, electric arc furnaces, which can generate the intense heat necessary to recycle steel scrap efficiently, now offer a shortcut to profitability in the innovative minimal segment of the steel industry. Similar trends are occurring in the automotive, textile, paper, food, and other major industries.

Baltimore Gas and Electric Co. is one utility that plans to benefit from industrial electrification. To build industrial loads, BG&E is encouraging the use of electrotechnologies for process heating. It exceeded its goal of 10,000 kW of new load from this source in 1983. In addition, BG&E is targeting new electricity loads for comfort heating and outdoor lighting in the industrial sector, which together yielded an increase of about 95,000 kW in 1983. To some extent, this success was aided by a rise in the rates for natural gas. The BG&E program emphasizes the importance of trade allies - contractors, architects, and engineers - as well as the general economic development of its service area.

Closely related to electrification in the industrial sector are new uses of electricity for the residential or commercial customer. The small computer, for example, represents a growing load that barely existed 10 years ago. The closest analogy may be the television set, which in 1950 was an exciting new item expected to consume a substantial 20 billion kWh by 1980 if, as expected, every home had one. What happened is that television sets in 1980 consumed 35 billion kWh - 75% more electricity than the amount predicted.

Consumers had more television sets per home and watched more hours per day than forecasters had expected. Consumer enthusiasm for color TV, which uses about three times as much electricity as a black-and-white set, further boosted utility sales, even though advances in technology had cut the consumption of a black-and-white set to one-ninth its 1950 level. If the home computer takes off as the television set did - and recent research shows that nearly 12% of the population already own or have access to a computer - the impact on utility loads could be quite significant in coming decades.

What's more, the garden, the playing field, and the shopping center are coming indoors in the form of the greenhouse, the domed stadium, and the enclosed mall. The energy required to heat, cool, and ventilate these enclosures will also represent very substantial new loads. Although the idea of automated homes and office buildings, with multiple functions controlled electronically by a computerized brain, may sound like starship science fiction, the reality is not so far away. Such innovations will mean a greater reliance than ever before on systems powered exclusively by electricity.

One role the utility can play is to encourage the development of these new applications through advertising or promotion, through joint ventures with retailers or contractors, and through pricing options that support such uses. On the other hand, the utility can take a neutral stance, merely serving whatever plan develops, or it can discourage new uses by its electricity pricing or service policies. Choosing the first posture, active encouragement, is most effective for building loads.

Adjustments in market share, a final option in demand-side planning, also focus on increasing utility loads. The difference is that these loads already exist and usually are served by gas or oil. For example, the aim here may be to win some of the home-heating load now served by fossil fuels.

Philadelphia Electric Co. is actively promoting electric heat pumps for this purpose. It captured 64% of the new home market for electric heating in 1983, with heat pumps accounting for about half the total. The goal for 1984 is 70%, with planned shares of 20% for resistance heating and 50% for heat pumps.

Facing a low load factor (47%) caused by a high summer air-conditioning peak and with sufficient capacity to allow for load growth, planners at Iowa Power and Light Co. have also selected the heat pump to boost winter sales. Further, like an increasing number of utilities, IP&L

uses structured planning to identify an optimal combination of demand-side moves: conservation in some areas, load management in others, and load building in still others. Demand-side planning in its many forms is proving to be a very flexible tool for achieving utility load shape changes, whatever those desired changes may be.

Current Research

EPRIs demand-side research is appropriately diverse. Three of the Institute's six technical divisions - the Energy Analysis and Environment (EA&E), Energy Management and Utilization (EMU), and Electrical Systems (ES) divisions - are actively engaged in some type of exploration to support the demand-side approach. EPRI's recently published End-Use Catalog: R&D Projects and Products examines over 200 end-use activities being managed by these divisions.

Planning activities center in the EA&E Division. Its Demand and Conservation Program has more than 50 projects in forecasting and planning electricity demand for all sectors of the economy. Demand-side management (RP2548) is a $1.6 million project that will generate some 13 guidebooks, providing utilities with the tools and information they need to undertake their own demand-side planning programs.

Other EA&E projects are exploring the effects of rate innovation and are creating techniques to gauge consumer response. Other projects are developing models that integrate supply and demand factors for utility planning and investment decision making. One such model, the load management strategy testing model (LMSTM), is already in widespread use.

In addition, EA&E is evaluating the risks associated with demand-side options and incorporating the results into planning tools.

The EMU Division provides the technologic cutting edge for implementing many of these demand-side plans. It develops and tests new methods of load management, provides conservation technology, and investigates how industrial loads can be reshaped through process electrification or customer generation. Further, EMU is sponsoring vigorous development of advanced heat pumps that will provide electric heating/cooling for a wide variety of residential and commercial applications.

The ES Division also plays a vital role in implementing certain types of demand-side options. It provides the technologic capability to control customer appliance use through direct communications links. In addition, its research develops the complex metering capability necessary to support TOU pricing and other innovative rates designed to influence patterns of customer demand.

Edison Electric Institute is making a major contribution to the industry's demand-side effort. As part of a national marketing program, EEI is preparing a 12-volume Power of Choice Bookshelf to help utility customer service and marketing managers develop innovative electricity demand management programs. The American Public Power Association and the National Rural Electric Cooperative Association are conducting ongoing demand management communication and demonstration programs with their members.

Load Shape Impacts

Demand-side planning offers a fresh way of looking at the utility universe and a varied menu of options. But what real difference will it make?

The most tangible point of impact is the planning target: load shape. A possible 1-12% reduction in utility peak loads is feasible. Successful peak clipping on this scale could translate to some $100 billion in capital savings from capacity deferral over the next 10-20 years.

Such savings are unlikely to accrue in the near future, however, because the impetus for some of the incentives has slackened. With demand growth already down from the historic 7% level to an annual average of about 2-3%, many utilities have now resolved the energy and capacity shortages that triggered load-trimming activity in the late 1970s. Conservation and reduction in load growth are no longer quite as pressing as before.

Right now strategic load growth has become very important. That includes both industrial electrification and new uses or increased market share in the residential and commercial sectors. These options are now of greater interest to 30% or more of the nation's utilities. However, the outlook for strategic load growth is mixed. Industrial electrification will probably forge ahead owing to the remarkable efficiency of the emerging electrotechnologies. But the very efficiency that makes these technologies attractive will reduce their load-building effects. Nationwide, the prospects depend heavily on the extent to which electric energy penetrates industrial markets traditionally served by gas or oil.

There's room for real growth in the commercial sector with ideas like the automated office building. We've only scratched the surface there. Between now and the year 2000, utility loads in the commercial sector are expected to grow nearly 40% to about 730 GWh annually.

Weather-related end uses in the residential and commercial sectors will grow less rapidly for the same reason that will restrain load growth in industry: gains in efficiency. Still, the widespread introduction of electric heat pumps could boost combined heating and cooling loads by some 25%, representing roughly a $6 billion increment to utility revenues. The main obstacle to achieving this potential is strong competition from the gas industry, which is also working on advanced high-efficiency technologies.

So the load shape changes translate into dollars saved and dollars earned, and they have a direct and tangible effect on utility financial performance.

But what about the less tangible impacts? They too can exert a powerful influence on a utility's well-being over the long term. That is why the demand-side approach emphasizes not only financial performance but also customer relations.

Customer Focus

Central to the concept of demand-side planning is mutual utility and customer benefit.

For years utilities have responded to customer demand without questioning it. Customers, for their part, have consumed electricity and paid their bills at the end of the month without knowing exactly how their money was spent. Can you imagine going into a supermarket with no weights and no measures and no prices marked on the goods, selecting your market basket, going to the cash register, and only then knowing what you've spent and what you've gotten for it?

The need for better two-way communication in developing a new partnership between the utility and the customer is needed.

I hope this is the beginning of a whole new philosophy that will include changing the way we meter and display information to customers. We have to give them more information - a better breakdown by end use - so they'll have a greater sense of control over their electric bills.

The sense of control that comes from having choices is critical in developing a solid accord with customers. That is why TOU rates and other options that leave consumption choices in the customer's hands will probably prove to be among the most effective means of meeting demand-side goals.

Because demand-side planning spotlights customer wants and needs in all their diversity, utilities are finding that they need a more detailed understanding of the factors that influence customer decisions. One of the analytic tools developed by EPRI for this purpose is the residential end-use energy planning system (REEPS).

REEPS breaks its analysis down so that utilities can study individual market segments. Within the market for central air conditioning, for example, REEPS has shown that purchase decisions are affected mostly by customer income, whereas utilization decisions depend mostly on electricity price. Total use, which represents the combined impact of these two types of decisions, is influenced more by income than by price. The upshot is that utilities wanting to modify air conditioner use as part of their demand-side strategy would do well to use income incentives (e.g., cash rebates) rather than price incentives (e.g., special rates).

Different relationships may hold for different end-use markets. REEPS and other planning programs now under development can help utilities design demand-side programs with an effective balance of income and price levers. The idea is to provide the type of incentives that research has shown customers to prefer.

More-detailed information on customer preferences and related costs/ benefits to the utility is perhaps the most pressing need in the development of demand-side planning. During the rush to implement early demand-side programs, utilities often conducted this evaluation after the fact. Now, with a more through and systematic approach, projecting probable customer response to various options becomes an integral part of the planning process.

Taking the Initiative

Demand-side planning is not a panacea. It is highly utility-specific. Current generating mix, customer load mix, end-use saturation levels, and demographies, as well as expected load growth, capacity expansion plans, load factor, load shapes for average and extreme days, regulatory climate, and reserve margins, all influence whether and how the demand-side approach can work for a specific utility. Still, demand-side planning offers a special opportunity for many utilities to take a hand in shaping the future.

The death-spiral hypothesis advanced by some critics of the industry suggests that utilities are caught in a spiral of rising production costs and sluggish demand. Rising costs increase prices, which further depress demand, and so on. This view reflects the dual assumption that utilities are captive to uncontrollable costs on the one hand and to mature markets on the other. But neither of these assumptions has to be the case.

Demand-side planning offers ways to cut both capital and O&M costs. Further, it offers a number of avenues to develop new markets for electricity without encouraging excessive or wasteful energy use. These new applications - computers, industrial lasers, advanced heat pumps for the home, to name only a few - benefit the customer and the utility. They are highly energy-efficient, so they help control customer energy bills at the same time as they build utility loads.

How, then, will the demand-side approach effect the way that utilities do business? It will force utilities to be more a efficient industry and a more competitive industry. The change will be fundamental: Customers will see a completely different industry - one that is more responsive, has a better understanding of their wants and needs, and offers a lower service cost than would be possible without demand-side planning.

The potential for influencing demand has been tried and proved in this industry for years but it has never done it before in an organized manner. Utilities never before had a formal planning structure that would allow a look at demand-side options in concert with supply-side options.

Future Research

This research has clearly demonstrated the potential that lies in demand-side planning. All criteria considered, I believe the timing is right and that the public and the utilities are ready for rate reform designed to promote a customer decision. Future research would be useful to analyze utility and customer objectives and match them to the tariffs. A change in the tariffs can force significant changes in the load shapes and revenues. My research has convinced me that this is a topic worthy of additional research.

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Vita

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